The Market for Power in New England:
The Competitive Implications of Restructuring

Prepared for the Office of the Attorney General
Commonwealth of Massachusetts

By

Tabors Caramanis & Associates

with

Charles River Associates

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Summary and Policy Implications

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by

Raymond S. Hartman

and

Richard D. Tabors[1]

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1.1 Overview and Objective

The objective of the study reported herein has been to evaluate the competitive structure of electricity generation and transmission in Massachusetts and the New England region

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[1] **Raymond Hartman is Director, Cambridge Economics, Inc. and was Vice President of Charles River Associates during a portion of the study. Richard Tabors is President of Tabors Caramanis & Associates and Senior Lecturer at Massachusetts Institute of Technology. The study was undertaken by Tabors Caramanis & Associates and Charles River Associates with support from Power Systems Inc. The study reflects the team efforts of Michael Caramanis, Scott Englander, Robert Fagan, Ross McEachern, Peter Spinney, and Ben Wisely.**

in order to determine whether that structure will support effective competition under industry restructuring. The study was conducted by a team under the direction of Tabors Caramanis & Associates and included Charles River Associates for development of factual materials on competitive issues in generation, Tabors Caramanis & Associates on transmission system structure and pricing and on demand evaluation and Power Systems Inc. on operations of the New England Power Pool.

This Section, Section One, summarizes the conclusions and implications of the study and focuses on the competitive position of the electric power industry in the New England Region. The factual sections supporting the study are presented as follows:

Section 2:	Analysis of the competitive structure and conduct of the providers of generation.
Section 3:	Analysis of the competitive issues in transmission
Section 4:	Projections of system demand
Appendix A:	Review of Alternative Operating Arrangements
Appendix B:	Methods of Transmission Pricing

1.2 Competition in Generation

As restructuring is being discussed in Massachusetts and the New England region, it is proposed that the generation sector be opened to full competition. This will mean that market forces rather than regulation will be relied up to protect consumer welfare.

Our factual analysis focused on the competitive position of generation in the region. It made use of the standard structural measure of competition as defined by the current Department of Justice Merger Guidelines, namely the Hirschman Herfindahl Index (HHI), to clarify the level of concentration of ownership and thereby the potential for anti-competitive behavior in the region.

1.2.1 Methodology

The results reported in this study are based on an evaluation of the operating positions of all generators and generating units in New England. The critical generating data were developed from published sources and include the size and output of each unit, its average heat rate, the type of fuel consumed, and its location, age and ownership. A second set of data required for the study was the hourly marginal costs for the region. These data are also publicly available.

Our methodology involved development of a supply curve for the region identifying the dispatch cost, identity, and ownership of each unit on the curve. A second step was to arrange the hourly marginal cost information into a cost duration curve (a concept parallel to a load duration curve) ordering the cost in $/kWh from the highest to lowest. Done in this manner the horizontal axis measures both the absolute number of hours and the probability that the cost per kWh will be greater than (or less than) a specific value.

Given the supply curve and the cost duration curve, it is possible to make the assumption that were all units available, a given point on the cost duration curve (system marginal cost) would have been supplied by one or more units whose marginal costs were the same. In this manner it was possible to create a cost duration curve that mapped precisely the expected ownership of the generating unit(s) on the margin at any point during the year. Further it was possible to state the duration that the unit was on the curve and to evaluate the competition in terms of ownership that was available to provide the next more costly energy in the loading order for the region.

This having been done, a series of tests were undertaken to define the competitive positions of every unit in the region. This study provided two conceptually new methods of evaluation of competition required in the electric supply industry. The first was to recognize and utilize the relationship between the supply curve and the cost duration curve in developing an analysis of the competition that could include not only price, but also time. The second, and more important recognition was that given the structure of the electric supply system, competitive markets must be divided into segments surrounding very small divisions in the cost duration curve. This is the case because competition can only occur between units within a tight cost band. In our analysis the logical cost band was only 1 mill per kWh, or roughly 5% of the total cost of the energy being supplied when one evaluated the prices along the marginal cost curve.

1.2.2 Results

A set of analyses were carried out to measure HHIs for the total region and for individual segments of the cost duration curve and supply curve. To summarize our findings for the total region and all generators the HHI was 2008. The HHIs for the group of generating units that set marginal price for most of the load for most of the year was only 1437.[2] This difference was expected given the dominance of the larger IOUs in base load generation. Note that this base load generation cannot influence the marginal cost so long as it is in operation. While the first of these values is somewhat above the Department of Justice Merger Guidelines' threshold of 1800 , the second, and it is argued most relevant figure, is not.

These results are best seen in the attached exhibits drawn from Section 2 of the report. For example, Exhibit 1 (Exhibit 12 in Section 2) shows both the histogram of marginal costs and the cost duration curve for the New England region for 1994. There are 192 generating units that can operate on the system marginal cost curve and the vast majority (> 70%) of the time the marginal cost lies between 15 and 25 $/MWH. Using this finding, Exhibits 2 through 4 (Exhibits 17A through 17C in Section 2) show the ownership of units along the relevant portion of the supply curve. Two points should be noted. The first is that there are a very large number of units lying between 15 and 25 $/MWH and second that there is no dominance in ownership in this range. Further, it should be noted that many of the units are owned by IPPs.

A critical element in evaluating competitiveness in the electric supply industry is the evaluation of the competitive possibilities for each generating unit in the relevant portion of the supply curve. Our analysis looked at the level of competition of each unit by developing a .5 and 1 mill "dead band" above the unit and assuming that those units within the dead band constituted its competition. A unit was said to have competition within this range only if units that fell in this range were owned and operated by a different entity. A 1 mill range approximately reflects the 5% price rule of the Merger Guidelines of the Department of Justice. Exhibit 5 (Exhibit 21 in Section 2) presents a

[2] We define this group of marginal generating units below.

histogram summarizing the competitive situation facing each generating unit. As can be seen, only 15 units face no competition in the 1 mill dead band range. The modal value is 5 competitors per 1 mill range; 7 of the units face more than 23 competitors in the range. Exhibit 6 (Exhibit 23 in Section 2) presents a second look at the concentration of ownership. In this exhibit we have taken into consideration the number of hours that a specific level of competition occurred. As can be seen, situations in which only a single unit (or owner) existed in the 1 mill dead ban accounted for 9% of the generating units but only 7.5% of the hours while 34% of the time there were two competitors in the 1 mill range. While 34% may seem large, the composition of ownership within this 34% is sufficiently diverse to prevent competitive problems.[3]

These results provide a clear picture of the level of concentration in ownership and thereby the ability of any individual owner to exercise anti-competitive behavior in the generating market in New England.

1.2.3 Conclusions

The section which follows provides, in summary format, the principle conclusions and policy implications of this study.

There is minimal opportunity for any owner to exercise market power in the New England region. This is the case because there is little concentration in ownership within the tightly defined competitive supply windows that were evaluated in this study (see above). Few of the 1 mill dead band windows investigated contained only one player. The majority contained 3 or more. Further, the proportion of time that a single competitor occupied a 1 mill window was small. The fact that this condition occurs a small percentage of the time would make it virtually impossible for a specific competitor to forecast its occurrence and then take advantage of it. The opportunity to lose revenue in hours when these conditions do not hold would, it appears, be greater than the gains that could be realized in the hours in which this competitive advantage could be exploited.

An important reason for the lack of concentration in New England is the significant number of independently owned generating companies in the region which is different from both other power pools such as New York and from other regions in the United States such as the Mid West. These include the Investor Owned Utilities, the Municipal Utilities and the Independent Power Producers. Taken together no one commercial entity controls any block of marginal generators, nor does any single generator appear on the margin for any significant amount of time.

Mergers of existing Investor Owned Utilities in New England could, we believe, have an impact on the competitive position of the supply industry. The impact of the merger would depend upon the absolute size of the merging entities and upon their generation ownership. While we have not evaluated the impact of each and every potential individual merger pair, it is clear that removal of certain competing firms from the

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[3] Specifically, the instances in which two entities occupy a single dead band occur only 15 times along the flat portion of the supply curve. Of these 15 times, no single pair of owners occurs more 3 times. The ownership represented in these 15 instances include Munis, NUGs and IOUs.

generation structure could have a significant impact on the competitiveness of the regional supply industry.

Therefore, if there are mergers, they should be evaluated by standard Department of Justice guidelines. Mergers of some of the smaller independent generation companies (NUGs and IPPs) will probably raise no competitive problems and may offer efficiency gains. However, mergers among any of the 3 largest companies should be resisted. Based upon analysis of minimum efficient scale in generation, there are probably no efficiency gains to be achieved by such mergers and the possibility for anti-competitive mischief would increase. Under all circumstances mergers should not be allowed to reduce the number of independent generating companies below five.

Non-Utility Generators or Independent Power Producers are an important part of the competitive market in New England. These units are significant in the quantity of energy supplied at the margin in the region. Our analysis concluded that, under current ownership, these generators could not be strategically operated so as to present a competitive problem in the region. We evaluated the impact of their being operated either as a group, i.e. as if owned by a single entity, or being incorporated into the ownership of the IOU to whom their output is primarily sold. In neither case did the increase in concentration significantly affect our conclusions regarding competition in supply.

If generating units are purchased and sold in a restructured industry it may be possible for a purchaser to acquire a strategically selected set of units that would offer opportunities for the exercise of market power. To accomplish this a buyer would, however, be required to control a significant number of units on the marginal cost curve and some base load units from which additional revenues could be derived. Given the small incremental differences in costs along the marginal cost curve in New England, only limited returns per kWh are likely to be possible. This would work against the profitability of such a strategy but certainly not insure against it. Purchases and sales of generating units will be evaluated by and be subject to standard Department of Justice guidelines.

Joint ownership of generating units in New England has been evaluated looking both at those units that are jointly owned at the present time and, as discussed above, in terms of IPPs that can be aggregated with their primary purchaser. In no instance does it appear that joint ownership affects competitive market positions because no limited combination of ownership of units on the supply curve could be shown to provide opportunities for the exercise of market power.

Withholding of Generating Units from the supply system as a strategy for gaining market power was not directly evaluated in this study. While this strategy frequently appears to be possible as a means of increasing the marginal costs and therefore the expected revenues to generation owners, it is difficult to implement and in the case of New England would not, we believe, be profitable. Base load units in the region are the largest units. They are also the most expensive per MW of capacity though the least expensive per kWh. Withholding them from the generating market means giving up their revenue stream. It would be necessary for a given owner of generation to control a major amount of generation on the margin that would operate only when the base load was withheld *and* be able to realize revenues in excess of that generated by the base load unit when operated in the competitive market for their to be any advantage in this strategy.

This situation is not likely to occur in the region and, significantly, with any quantity of bilateral contracts in play that cover the base load generation, this behavior would not, in all likelihood, result in additional revenues since the contract would be for delivery of energy, if not from the unit then from the market. Therefore we see no competitive problems arising from this issue.

Growth in Load in the New England region has been slow over the past decade due to many factors including the restructuring of the regional economy and the cost of energy, including electricity. It is clear that eventually the demand for electricity will outstrip the current supply. The speed with which this will occur will be a function of the price and other exogenous growth factors. We have evaluated the impact on growth in demand of a drop in price of 25% brought about by the restructuring of the electric supply industry. We have assumed an elasticity of demand with respect to price assumed to be -0.1. The price reduction was chosen to reflect earlier estimates of the potential for cost savings. The price elasticity chosen is based on estimates found in the literature.

The conclusion from this evaluation is that growth in load in the region will not have a short run effect on the competitive position of any player in today's market. The increase in consumption, while being important, reflects only an increase in 2.5% per year. This has the effect of increasing the summer peak by 17% over the next ten years. By comparison, the NEPOOL high demand growth scenario increases summer peak by 22% during this same time period. We see no evidence to indicate that a reduction in price will change our basic conclusions with regard to the competitive structure of supply in the region.

Unit retirements expected in the region during the next 10 years are quite limited. Matched against many of these are increases in expected capacity from refurbished and repowered facilities. The only scenario in which there will be a significant impact on the marginal cost curve, and hence on the competitive position of generating companies is one in which all Nuclear units are forced to close before their anticipated physical life term. Under these circumstances the region will be tight on capacity and significant shifts along the supply curve will occur. There are a number of sharp steps in the higher-priced end of the supply curve which would offer opportunities under this unlikely scenario for the exercise of market power by those entities controlling these units. It should be remembered, however, that these high-cost units can be quickly replaced by new, higher efficiency generating units that can be brought on line in a matter of 2 to 4 years and/or by DSM initiatives.

Retirement of units other than nuclear will have only a minimal, if any impact, as no single unit or set of non-nuclear units command a significant portion of either base load capacity or, more importantly, position on the regional marginal cost curve.

Fixed O&M costs were not evaluated. These values were not available from published sources. Rules of thumb and information from generic sources such at the EPRI *Technology Assessment Guide* did not provide additional insights into the impact that might be possible because of differences in fixed O&M. As was discussed above, however, the only likely condition in which this variable would have a significant impact on the conclusion of this study is one in which there are significant cost calculation differences in nuclear generators brought about by redefinition of marginal costs to include fixed O&M costs. Simple calculations of the likely impact of transfer of fixed O&M to a variable cost (because it is avoidable if the units are never run) indicates that the marginal costs of these units will roughly double. While we did not address this issue directly in the report, it is clear that nuclear units would move from baseload to intermediate and could, under some circumstances, find themselves on the marginal portion of the supply curve. Because of the must-run nature of these generators it is unlikely that they could or would be cycled, requiring either that they not be operated or that they be bid to operate under some circumstances at returns lower than their newly defined marginal costs.

Finally, notice that the structural rules of thumb underlying **FERC's market-based pricing test** are no longer relevant for the restructured industry in New England. Specifically, in prior market-based rate filings, the FERC has generally held that if an applicant possessed less than a 20% market share in all destination markets (that is, for all "Tier 1" entities), that applicant did not have market power.[4] In the restructured industry, the distinction of "Tier 1 entity" will disappear and all participants will be interconnected on the grid. Hence, the more standard rules of thumb concerning market definition under the Merger Guidelines will be those that are relevant.

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[4] Louisville Gas and Electric Company, 62 FERC, 61016 (1993) at paragraph 61,146.

1.3 Competition in Transmission

There are two critical elements in evaluation of transmission services in the New England region. The first is availability or constraints; the second is ownership. The level and frequency of constraints are critical to define the transmission pricing regime that can be applied in the region. It is acknowledged that the spatial marginal cost is the theoretically correct starting point for development of transmission pricing. Spatial pricing uniquely provides the methodology for pricing of transmission services into and out of the transmission grid at every point in both time and space. While correct, this level of detail is generally not needed since the information contained in the methodology can be aggregated in time (to TOU types of tariffs) or space (zonal tariffs) or both (postage stamp tariffs). As will be discussed below, few constraints appear in today's New England transmission system and as a result an aggregation over both time and space appears to be appropriate until such time as significant constraints appear.

Transmission ownership is an issue in New England. There is high concentration of ownership in the region. A significant question is whether this ownership can be used to restrict access to the transmission system.

1.3.1 Methodology

The approach taken to evaluate transmission focused on development of a information base characterizing the operating conditions in the region. Within NEPOOL, conditions in which it is necessary to move from strict least cost dispatch fall under a limited number of the NEPOOL operating rules, in this case those contained in OP4. OP4 provides for a set of steps to be undertaken by the system operator under conditions in which the supply available to the system does not or may not match adequately the load, or conditions in which the transmission system can not or may not be able to move energy from the least cost suppliers in the region to all load points in the region. This latter condition reflects a transmission constraint.

The approach taken in this study was to evaluate all transmission related emergency actions that had occurred on the system over the period 1983 to 1995. These data were received directly from NEPOOL, and the results of the analysis were confirmed through discussions with knowledgeable former and present operating personnel at NEPOOL.

Two measures of ownership were developed for this study. The first and most obvious was a tabulation of miles of transmission service at or greater than the 115 kV level. The second was to tabulate the ownership of the critical interfaces in the New England region as defined by NEPOOL.

1.3.2 Results

The frequency of transmission-related OP4 actions between 1983 and 1995 has changed dramatically. During the late 1980's, specifically 1987 and 1988, there were between 25 and 37 OP4 actions taken each year. Of these, as many as 15 were related to transmission constraints involving actions 12 to 15[5]. In 1988, there were frequent occurrences of transmission limits in the region. By 1990, however, a series of transmission-related investments had been made in the region to relieve constraints on the critical interface serving Boston. The result was that after 1989 there was only a single OP4 action that involved a transmission limitation, which occurred in 1994.

To help confirm these facts, three experts who have been involved in the New England power system for their working careers were interviewed as to the severity and likely occurrence of transmission constraints in the region. These individuals were asked to estimate the proportion of the time that one or more transmission constraints occurred on the system and to estimate and describe the cost differentials that occurred on the two sides of the constraint when it occurs. The three provided corroborative information that constraints occurred less than 5% of the time in the region and that when those constraints occurred the difference in cost between the two sides of the constraint was less than 5%. The similarity in operating costs and generation type means that the units used on the two sides of the constraint differ only slightly from each other.

The second portion of our analysis focused on the pattern of ownership of transmission assets and the critical transmission interfaces in the region. Evaluating the ownership of transmission miles in the region showed that ownership is concentrated (80%) in the hands of only 3 utilities in the region. In order of size, these are Northeast Utilities, New England Electric Systems and Central Maine Power. Of the 11 other owning transmission utilities, none owns as much as 10%.

Evaluation of the critical interfaces in the region provides, as anticipated, a similar though not identical picture. NEPOOL defines the critical interfaces in the region. Our tabulation rule was that an interface was owned by an entity if it controlled *either end* of that critical interface. Using this definition, Northeast Utilities, New England Electric Systems, Boston Edison and Central Maine Power control 63% of the thermally-based critical interfaces and 45% of the stability-based critical interfaces.

1.3.4 Conclusions

Within the New England region two forces are at work in the development of a competitive electric market. The first is that the region is, effectively, free of transmission constraints at the present time. Given this structure, there is little to constrain the location decisions of either new supply or demand in the region, i.e. from the perspective of transmission constraints and thereby transmission pricing, there is nothing to differentiate between locations in the region. Clearly, this conclusion is time and condition dependent. Should generation currently located near to Boston be retired, or should demand patterns swing dramatically, this conclusion could change.

Ownership of transmission in the region is highly concentrated. At present neither

[5] Actions 12 to 15 represent the most sever system responses.

Independent Power Producers nor municipal utilities own significant transmission assets, though the municipals do have specific rights to transmission that have come from individual agreements associated with jointly owned units and through rights associated with pool planned units.

1.4 Summary

There are two overriding conclusions to be drawn from this study. First, the current structure of generation in New England is sufficiently competitive to allow restructuring to proceed. Sufficient consumer protection will be provided by market forces and, therefore, regulatory oversight of generation can be removed.

Second, having said this, it is critical to understand that the task of implementing restructuring the electric supply industry has only begun. While currently competitive, it is possible for the generation market to become less competitive in the future, due to consolidation. Any such consolidation should be scrutinized in the future for antitrust implications. Furthermore, details of restructuring are still to be worked out. For example, the detailed procedures for selling energy still need to be clarified. Such procedures have implications for the operation and performance of the generation market. As was learned with the restructuring of the UK electricity supply industry, procedures for selling energy facilitated exploitation of the non-competitive structure of the industry.

Section 2.

Issues in New England Electricity Supply

by

Charles River Associates

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2. Issues in Supply

2.1 Definition of the Functions Within the Supply Industry

2.1.1 Supply

The function of supply within the NEPOOL market is characterized by internal regional generation of electricity and net electricity imports into the region from the adjacent New York Power Pool and Canadian provinces of Quebec and New Brunswick. Although DSM services can be thought of as "negawatt" supplies, the focus in this report is on generation and net imports of electricity.

2.1.2 Aggregation

Aggregation of electricity supply can be defined as the control of a collection of generation sources used to produce electricity. Within the current industry structure, aggregation of generation occurs when entities (such as investor-owned utilities) operate all of their individual generation units in a carefully considered manner to ensure the most efficient and effective use of their total generating resources. Aggregation of supply also includes all manner of control and operation of generation resources in tandem with carefully considered purchases and sales of wholesale power, resulting in a portfolio of available electricity controlled by an entity. An entity without any generation resources of it's own can also aggregate supply by purchasing the generation output of others and having control over the portfolio of electricity purchased.

Current bulk power transactions between regional entities serve aggregation functions. An entity with a commitment to deliver power to end users may need to purchase electricity from the bulk power market to meet obligations. Similarly, an entity with an excess of generation resources enters the bulk power to offer sales of power to those short of supply.

2.1.3 Operation

The operation of the electric power supply industry within the six state region of New England is currently coordinated by NEPPOL, whose members account for 95.5% of electric power production, import and transmission. The operation of the system is discussed in chapter 3 and issues of operation under an ISO are explored in Appendix A.

2.1.4 Delivery (Wholesale and Retail)

The delivery of electric power to final customers is accomplished by distribution companies and aggregators of delivered wholesale power.

2.2 NEPOOL Generation Market Structure

2.2.1 New England Generation Capacity

2.2.1.1 Overview

New England's electric generation dispatched by NEPOOL is composed of approximately 407 individual generation units owned by investor-owned utilities (IOUs), non-utility generators (NUGs), and municipal entities (including municipal wholesale providers and cooperatives).[6] Additional generation not dispatched by NEPOOL is controlled by individual, independent entities, and is used to serve load excluded from NEPOOL's demand forecast (e.g., customer self-generation). Additional capacity is available through interregional transfers from New York State and Canada[7]. A significant amount of firm *energy* sales are transacted with Quebec, but only a small fraction of available transmission capacity from Quebec to New England is contracted as a capacity purchase[8].

2.2.1.2 New England Generation By Fuel and Unit Type

New England's electric generation capacity is composed of units using nuclear, hydroelectric, fossil, renewable, and refuse fuels. All standard types of power units are represented - thermal steam (oil, gas, coal, nuclear, wood, refuse), combustion turbine (oil, gas), internal combustion engine (oil, gas), hydraulic turbine (hydroelectric), and wind turbine.

Exhibit 1[9] illustrates the breakdown of generating capacity by ownership, fuel type and unit type.

Exhibit 1. New England Generating Unit Summer MW Capacity by Fuel Type, Unit Type and Ownership Type

A number of oil-fired units are also capable of burning natural gas. The 1995 NEPOOL Forecast of Capacity, Energy, Loads and Transmission - 1995-2010 indicates that approximately 3,900 MW of utility and municipal-owned capacity has dual fuel capability, primarily with steam units (83 percent). The dual-fuel capability is included in Exhibit 1 as part of capacity groupings under oil (combined cycle, combustion turbine, internal combustion, and steam unit types) and gas (IOU and municipal-owned combined cycle) fuel types. Exhibit 1 uses the primary generation fuel to categorize generation units by fuel. Dual-fuel capable units are listed only in one fuel type category, the unit's primary generating fuel.[10]

While nuclear-fueled generation comprises approximately 26 percent of the region's capacity, it's share of total electric energy generated is approximately 40 percent, due to its use as a fuel for base-load generating units. Exhibit 2 shows the production of electric energy (millions of kWh or gigawatt-hours (GWH)) by fuel source in New England. It also indicates the net amount of electricity imported by New England, and the effect of operating pumped-storage generation units, which are net energy users but provide capacity during on-peak hours.

Exhibit 2. 1994 NEPOOL Electric Energy Production (GWH) by Fuel Type

2.2.1.3 New England Generating Capacity by Ownership Status

[6] North American Electric Reliability Council Electricity Supply and Demand Database, 1995. This is the same information available from NEPOOL's 1995 Capacity, Energy, Loads and Transmission report (CELT).
[7] See section 2.2.6 for additional information on imports and exports of electricity between New England and these regions.
[8] This is due to reliability concerns and availability of Hydro Quebec power. See section 2.2.6.
[9] Most exhibits to this chapter are gathered at the end of this chapter.
[10] Dual fuel units operate on natural gas when it is available at a price lower than fuel oil.

List of Exhibits

Investor-owned utilities own approximately 83% of New England's generation, and operate an even greater share[11]. Non-utility generators own approximately 11 percent of capacity; the remaining six percent is owned by municipalities, cooperatives and municipal wholesale electric companies. Exhibit 3 shows generation capacity by fuel type across individual IOUs, an aggregate of NUGs, and an aggregate of municipalities (and municipal wholesalers and cooperatives) in New England. Exhibit 4 provides the legend for the abbreviated company names in Exhibit 3 and Exhibits 5A, 5B, and 5C.

Exhibit 3. NEPOOL Generating Unit Capacity by Ownership and Fuel Type

Exhibit 4. Generating Unit Ownership Legend

Code	Company Name	Code	Company Name
BECO	Boston Edison	MMLD	Marblehead Municipal Light Department
BELD	Braintree Electric Light Department	MMWEC	Massachusetts Municipal Wholesale Electric Company
BHE	Bangor Hydro-Electric Company	MPLP	Milford Power Limited Partnership
CES	Commonwealth Energy System	NAED	North Attleborough Electric Department
CMEEC	Connecticut Municipal Electric Energy Cooperative	NEP	New England Power
CMLP	Chicopee Municipal Lighting Unit	NHCO	New Hampshire Electric Cooperative
CMP	Central Maine Power	NU	Northeast Utilities
EUA	Eastern Utilities Associates	PMLD	Princeton Municipal Light Department
FGE	Fitchburg Gas and Electric	PMLP	Peabody Municipal Lighting Unit
GBPC	Great Bay Power Company	SELP	Shrewsbury Electric Lighting Unit
HGE	Holyoke Gas and Electric	TMLP	Taunton Muncipal Lighting Unit
HLPD	Hudson Light & Power Department	UI	United Illuminating
HMLP	Hingham Municipal Lighting Unit	UNITIL	Unitil Power Corp.
IMLD	Ipswitch Municipal Light Department	VTGP	Vermont Group
MIDD	Middleborough Gas and Electric Department		

Source: NERC, 1995.

Exhibits 5A, 5B and 5C provide breakdowns of generation capacity in New England by individual company and ownership stans. Generation is owned by eleven IOUs, three municipal wholesalers or cooperatives, fourteen municipal entities (most of the latter located in Massachusetts), and by non-utility generators[12]. These exhibits

[11] Municipal entities own a fraction of the output of some generating units which are operated by investor-owned utilities.

[12] There are over 100 non-utility generators in New England. Exhibits 5A-5D aggregate the capacity of these NUG generators leading to a conservative estimate of market concentration. This report does not contain a detailed analysis of the corporate ownership of NUG capacity. There are at least six national energy service companies much of the owning NUG generation in

distinguish between generation owned by NUGs and that owned by IOUs and municipal entities, and provides a breakdown of capacity shares for four illustrative cases of the generating market:

- Case I: Total capacity with NUGs included as separate generating entities;
- Case II: Total capacity with NUG generation apportioned to the purchasing entity;
- Case III: Total capacity with NUGs included as separate generating entities and joint ownership shares assigned to the operating entity; and
- Case IVTotal capacity for those generation units that comprise the bulk of the marginal generating units.

In Case I, the market for generating capacity in New England includes non-utility generators separate from the entities (mostly IOUs) that purchase their power. Case II illustrates the increased market concentration which results if the NUG capacity is considered as part of the generating portfolio of the purchasing entity. This result is particularly apparent for the largest IOUs, as they purchase most of the NUG capacity. Case III illustrates the increased shares of generation capacity controlled by IOUs if municipal ownership shares and other jointly-owned generating capacity is apportioned to the operating entity.

Case IV illustrates reduced concentration of control in the generation market that results when only non-baseload units are examined. The influence of NUG ownership and Northeast Utilities' larger share of baseload generation capacity is seen in Exhibit 5D, as overall NUG shares increase relative to Exhibits 5A or 5C, and NU's share of non-baseload capacity decreases compared to its share of overall generation capacity.

Exhibit 5A. Capacity and Shares of NEPOOL Generation Units by Ownership, NUGs Separate

Exhibit 5B. Capacity and Shares of NEPOOL Generation Units by Ownership, NUGs Apportioned to Purchaser

Exhibit 5C. Capacity and Shares of NEPOOL Generation Units by Ownership, Joint-Ownership Apportioned to Operating Entity

Exhibit 5D. Capacity and Shares of NEPOOL Marginal Generation Market Based on 192 Marginal Units by Ownership, Joint-Ownership Apportioned to Operating Entity

2.2.1.4 Age and Size of New England Generating Units

<u>Age of Generating Units</u>

Exhibit 6 displays the age of generating units in New England according to capacity and fuel type. More than 60 percent of the capacity came on-line between 1960 and the early 1980s; a second large block of capacity approximately 25 percent, has come on-line since the early 1980s.

Exhibit 6. Age of NEPOOL Generating Capacity by Fuel

More than 50 percent of the capacity added in New England since 1984 has been built by non-utility generators. The NUGs share of the market for new non-nuclear generation is even greater; *more than 90 percent of the non-nuclear capacity added in New England since 1981 was built by NUGs*. Exhibit 7 illustrates NUG capacity installation over the past 15 years. In the exhibit generating capacity installed 1981-1994 is net of retirements.

Exhibit 7. New England Generating Capacity by Time Period and Ownership Type

	IOU Capacity (MW)	NUG Capacity (MW)	Total Capacity (MW)

New England, with many smaller entities owning the rest.

Pre-1981	18,754	1	18,755
1981-1994	2,970	2,757	5,727
Total, 1995	21,724	2,758	24,482

The portion of generating capacity built by nonutility generators since 1981, as shown in Exhibit 7, illustrates the impact of the Public Utilities Regulatory Policies Act (PURPA) of 1978. Entry of nonutility players into the generation market commenced with the passage of that law, which required utility companies to purchase power from qualified nonutility generating facilities.

Size of New England Generating Units

Exhibits 8 and 9 present information on the size of generating units in New England. A small number of large units constitutes the majority of generating capacity in New England. For example, the twenty largest generating units have summer capacity ratings of at least 385 MW and together comprise approximately 50 percent of the total New England capacity.

Exhibit 8. Histogram of Unit Size for 407 NEPOOL Units

Exhibit 9. Scatter Plot of NEPOOL Unit Dispatch Cost vs. Unit Size for 407 Units

Exhibits 8 and 9 demonstrate principles of generating unit marginal cost scale economies:

- Historically, larger units tended to have greater economies of scale with respect to marginal operating costs; i.e., almost all large units have relatively low operating costs; and
- Recent capacity installations have relatively low operating costs, as newer combined cycle technologies allow for low operating costs in smaller units.

2.2.1.5 Joint Ownership of Generation Units

Approximately 49 percent of the generation capacity in New England is owned jointly. However, the extent of joint ownership - the incidence of many owners or owners with large shares of capacity in any given jointly-owned unit - is small, especially for non-baseload units. Except for six of the eight nuclear generating units and three large thermal steam units, the majority owner of jointly-owned units has a greater than 80 percent share in all but a few instances, and those cases involve relatively small units. Exhibit 10 lists the 36 jointly-owned units in New England, including the majority owner and share, number of owners, and the fuel and unit type.

Exhibit 10. List of NEPOOL Jointly-Owned Generating Units

Joint ownership of generating units in New England can be characterized as follows:

- When joint ownership is explicitly accounted for in computing shares of generation capacity, a less concentrated market is seen. This is seen by comparing Exhibits 5A and 5C.
- Joint ownership is seen primarily with nuclear units, and municipal ownership of small shares of capacity.
- The potential of market power in marginal generation is not affected by patterns of joint ownership.
- Municipal ownership of small shares of capacity might better be characterized as a firm purchase contract from the operating entity's unit.

2.2.2 The Relative Cost of Generation in New England

2.2.2.1 Overview

In a perfectly competitive generation market, competing suppliers will provide power at true marginal costs - or the average variable costs associated with producing power - when they are the marginal supplier. Marginal costs consist of two primary components:

- Fuel; and
- Variable operation and maintenance.

Currently, New England generation is dispatched based on rank order of marginal costs approximated by each unit's heat rate multiplied by the fuel costs for the unit, plus the variable operation and maintenance costs (nonfuel) for the unit. NEPOOL submits this information to the Federal Energy Regulatory Commission, along with system load data, for 8,760 hourly periods for each year. This information is available to the public. However, the hourly data submitted includes - in addition to the fuel and O&M components of generation cost - the transmission penalty factors associated with each unit at the specified hour. To estimate the true marginal *generation only* costs, these factors would need to be backed out of the data. Since unit-specific and time-specific transmission penalty factor data are not readily available (nor easily estimated), we have used reported system lambda data when using the marginal cost of NEPOOL system generation in our analysis of individual unit marginal generation markets.

2.2.2.2 System Lambda and System Load

The relative cost of generating electricity in New England is represented by the value of NEPOOL's system lambda, which indicates the average operating/dispatch cost in $/MWH or mills/kWh (tenths of a cent per kWh) of the marginal unit (the most costly unit) dispatched by the pool.[13] The data describe hourly values for system lambda and the accompanying system load for each of 8,760 hours per year. Exhibit 11 illustrates the weekly average lambdas and load for three periods: on-peak (M-F, 11AM-6PM), shoulder (M-F, 8-11 AM, 6-11 PM) and off-peak (M-F, 11PM-7AM, Saturdays and Sundays).

Exhibit 11. 1994 NEPOOL Weekly Average Load and System Lambda for Peak, Off-Peak and Shoulder Periods

As seen in Exhibit 11, the system lambda varies over the year. It fluctuates in response to system load, availability of generation capacity, weather conditions, and abnormal events such as the loss of a key transmission line or generating unit. It tends to be higher during high load periods, and lower during low load periods. However, scheduled maintenance of generating units during low load periods and consequent higher availability of generation units during high load periods reduce the variation in lambda between these periods.

Exhibit 12 is a histogram and cumulative frequency diagram of system lambda data for 1994. It depicts the distribution of lambda values across the total number of hours per year. It represents a cost-duration profile of New England generation capacity.

Exhibit 12. Histogram of 1994 NEPOOL System Lambda

Exhibit 13 further clarifies system load using a histogram and cumulative frequency diagram of system load (MW) data for 1994. It depicts the distribution of system loading across the total number of hours per year. It represents a load-duration profile of New England electricity demand. Exhibit 14 compares this information for 1993 and 1994.

Exhibit 13. Histogram of 1994 NEPOOL System Load

Exhibit 14. Comparison of 1993 and 1994 NEPOOL System Lambda and Load

Exhibit 15 shows electricity generation costs (including transmission penalty factors) for New England for 1994. It illustrates the amount of electricity produced at any given level of dispatch cost. It was created by summing up the

[13] As mentioned in the paragraph above, these data include transmission penalty factors.

total electricity produced (based on the hourly MW load) at each level of cost (described by system lambda). For example, approximately 50 percent of the total electricity produced in New England in 1994 was generated at a dispatch cost of less than 20 mills/kWh ($.02/kWh); the remaining 50 percent was generated at a dispatch cost of higher than 20 mills/kWh.

Exhibit 15. Cost Duration Curve of 1994 NEPOOL System Energy Delivered

The previous five exhibits illustrate the following:

- System lambda is in the relatively narrow range of 13 to 28 mills for approximately 95 percent of 1994 hours.
- NEPOOL load exceeds two-thirds of the available capacity for only 10 percent of 1994 hours.
- While system load changes considerably between seasons, system lambda does not vary proportionately, as scheduled maintenance of generation influences average system lambda.

2.2.3 The Marginal Cost of Generation in New England

2.2.3.1 Overview

The marginal cost of generation in New England can be described by a supply curve illustrating the relative marginal cost or dispatch cost of all available generating units in the region. The shape and length (overall available capacity) of this supply curve will vary depending on generation unit availability. It is constructed by ranking all units in the region from lowest to highest marginal cost (dispatch cost), and graphing the resulting costs against the cumulative capacity until all units are included. The supply curve is a very helpful and powerful tool used to assess marginal generation costs. While there exists some uncertainty around the data used to develop the curve, it is a realistic depiction of the relative technical marginal costs[14] of New England generation.

2.2.3.2 Supply Curve of New England Generation Under Three Capacity Scenarios

Exhibit 16 presents the supply curve for three scenarios of generating unit availability. The curve furthest to the right depicts full availability of all units in the region; the total capacity of 24,483 MW is available at increasing marginal costs from $0.00/kWh (lowest cost) to $0.10/kWh (highest cost). The curves to its left illustrate two capacity constrained scenarios:

- The middle curve represents a 14 percent (of maximum) capacity shortage, and assumes two nuclear and six relatively large fossil steam units being unavailable; and

- The extreme situation of 29 percent unavailability, shown by the curve on the left, illustrates the unavailability of three nuclear and 11 relatively large fossil steam units.

These scenarios were chosen to describe constraint scenarios that could arise from scheduled and unscheduled outages of generation units. The curve on the right describes the maximum generating capacity situation in New England, generally occurring during periods of peak demand when there are no scheduled or unscheduled outages. The curve on the left represents a very extreme scenario encompassing supply constraints arising from scheduled maintenance and unscheduled (forced) outages of either generating units or transmission lines needed to transmit power from a unit. The middle curve represents an intermediate scenario, describing, for example, the capacity situation occurring during low load months with no unscheduled outages.

Exhibit 16. NEPOOL Dispatch Cost: Supply Curves for Three Capacity Availability Scenarios

The three supply scenarios are crossed by two lines representing peak demand during the highest and lowest load periods of the year. These values can be used to assess the extreme operating points of the supply system.

For example, if all capacity is available and the peak load reaches 20,519 MW (the 1994 summer peak load), the marginal operating unit will be one that has a dispatch cost of approximately $0.028/kWh. In the same supply scenario when load reaches minimal levels of, for example, 8,000 MW, the marginal unit's operating cost is approximately $0.006/kWh, or six-tenths of a cent per kWh (6 mills/kWh). Under an extreme supply scenario such as the one depicted by the curve on the left, at a load of 14,800 MW (approximate projected peak load for the low

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[14] The technical marginal costs are the marginal costs calculated using engineering data on unit heat rates and estimates of fuel prices and operation and maintenance costs. In an unregulated generation market, generation owners may choose to set marginal prices at levels different from marginal costs. For this analysis, heat rates are taken from DOE/EIA Form 860, "Annual Electric Generator Report". Fuel and O&M costs come from NEPOOL's, "1995 Summary of the Generation Task Force Long-Range Study Assumptions." The dispatch cost also includes medium load penalty factors. Using dispatch costs excluding penalty factors would produce results that are essentially the same.

load period of the spring of 1996), the marginal unit cost is also approximately 28 mills/kWh.

Different supply and demand scenarios can be analyzed in this fashion by moving along appropriate (anticipated or unanticipated) supply curves according to estimates or evidence of demand levels and accounting for reserve requirements.

2.2.3.3 Supply Curve of New England Generation By Unit Ownership

The supply curve can be further analyzed to see which type of units are located at what points, and/or to assess the ownership status of units or groups of units along the curve. Exhibits 17A, 17B and 17C depict each of three portions of the supply curve and show ownership status:

- At the beginning portion of the supply curve (Exhibit 17A);
- At the intermediate portion of the supply curve (Exhibit 17B); and
- At the end of the supply curve (Exhibit 17C).

These three regions approximately represent (respectively) base-loaded units; units used to serve load above baseload (intermediate load); and units used to serve load only during periods of extreme load or constrained capacity. Each of the graphs include the transition portion of the supply curve, where costs tend to increase significantly faster as the next marginal unit comes on-line compared to the flatter section of the curve preceding it. The graphs illustrate the extent of unit ownership along the marginal cost curve by the different New England entities[15].

Exhibit 17A. NEPOOL Supply Curve, Baseload Region, by Ownership Type

Exhibit 17B. NEPOOL Supply Curve, Intermediate System Load Region, by Ownership Type

Exhibit 17C. NEPOOL Supply Curve, High System Load Region, by Ownership Type

The following ownership patterns emerge from examination of Exhibits 17A, 17B and 17C:

- There are relatively few instances where one entity controls more than one or two consecutive generating units along the supply curve (NUGs are indicated with one symbol; with a few exceptions, , all NUG units are independent of each other. This is also true for the symbols indicating municipality-owned units);
- In the region of the curve where most of the marginal dispatch hours occur - beginning at a dispatch cost of approximately 15 mills/kWh up to a cost of approximately 30 mills/kWh - the units available for dispatch are owned by many generators, including all of the large IOUs and almost all of the non-utility generation in NEPOOL;
- The locations of single-entity ownership of successive units occurs mostly at the upper end of the supply curve, historically where relatively few hours of occur annually; and
- An example of single-entity ownership of consecutive units can be seen by examining Exhibit 17AB, at the cumulative capacity area beginning with 11,052 MW. new England Electirc System owns three consecutive coal-fired steam units, with a total capacity of approximately 1,062 MW.

2.2.3.4 Supply Curve of New England Generation By Unit Type/Fuel

Exhibit 18 illustrates unit type along the supply curve. In general, hydroelectric, refuse-fired and nuclear units are dispatched at the lowest marginal costs; fossil-fueled and wood-fueled steam, and fossil-fueled combustion turbine or

[15] Exhibits 17A, 17B and 17C include all generating units owned or controlled by investor-owned utilities, NUGs, municipal wholesalers and municipalities. Jointly-owned units are assigned to the operating or controlling entity.

combined cycle units at the intermediate stage of costs; and fossil-fueled internal combustion and jet engine units as peaking units at the highest level of costs.

Exhibit 18. NEPOOL Supply Curve by Fuel and Unit Type

While the generalizations described above hold for most of the supply curve, the location of pumped storage units along the curve must be noted. The capacity of pumped storage units - a total listed capacity of 1,682 MW in NEPOOL - is generally available for only a fraction of each day. The capacity is made available by pumping water (with reversible hydraulic pumps/turbines) to reservoirs during periods of low demand and low dispatch cost, and using the capacity (by drawing down the reservoirs through the hydraulic turbines) during periods of high demand and higher dispatch cost. The units are used to displace capacity that otherwise would come from non-baseload units, which are relatively expensive compared to the baseload power used to pump the water during the off-peak periods. The actual point along the supply curve at which the pumped storage units are dispatched will vary according to the season and the daily system lambda profile. In the marginal unit analysis undertaken for this project, the units have been assigned a dispatch cost as if they were hydro units - zero marginal cost. A more refined analysis would account for the unique nature of the pumped storage plants, and place the units at a point further up the supply curve.

2.2.4 Competition Analysis for Marginal Units

2.2.4.1 Overview

Any analysis of competition usually focuses on the size of a given market under consideration and the number of participants within that market. In many cases, the size of the market is determined by a hypothetical price increase of five percent.[16] One way of examining the competition facing each generating unit is to use the five percent rule to analyze patterns of ownership of marginal units along the supply curve. A marginal unit is defined as the unit whose marginal cost equals system marginal cost.

For example, for the generating unit whose marginal cost is 20 mills/kWh, there are 10 hours per year when the system is dispatching units at exactly 20 mills/kWh (within NEPOOL in 1994). We can look forward along the supply curve, and observe that unit and all others in the immediate market (defined as the same cost category plus 5 percent - in this case, the 20 - 21 mills/kWh range) that will compete[17]. Competition will be workable on structural grounds within this narrowly defined "market", if there exist a sufficient number of competitors. Exhibit 19 lists the generating units along this portion of the supply curve, ordered by increasing dispatch costs. In this instance, there are seven generating units whose marginal costs lie in the 20 - 21 mills/kWh range. Ownership of the seven units is divided between two IOUs and four non-utility generators (independent of each other).

Exhibit 19. Generating Units Along Supply Curve at 20 - 21 Mill/kWh Dispatch Cost
Source: NERC Electricity Supply and Demand Database, 1995, and TCA.
Exhibit 19 lists a total of 6 different entities (NU, NEP, and four NUGs) with units operating in the marginal cost

[16] "Formally, a market is defined as a product or group of products and a geographical area in which it is sold such that a hypothetical, profit-maximizing firm, not subject to price regulation, that was the only present and future seller of those products in that area would [find it profitable to] impose a 'small but significant and nontransitory' increase in price above prevailing or likely future levels." See United States Department of Justice Merger Guidelines, June 14, 1984, Section 2.0, and United States Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, April 2, 1992, Section 1.0. In the past, the Justice Department has taken a 'small but significant' increase to be 5%.

[17] Parenthetically, there are 491 hours per year when the system is dispatching units between 20 and 21 mills/kWh

range defined by the 20 - 21 mill/kWh bin. No one entity has a monopoly on the generation available in this marginal generation "market".

The remainder of this section documents structural measures of the competition facing each of 192[18] marginal generating units under two alternative hypotheses regarding the size of their relevant market:

- Each unit competes with all units within 0.5 mills/kWh of its dispatch cost; and
- Each unit competes with all units within 1.0 mill/kwh of its dispatch cost.

These deadbands have been chosen arbitrarily. Notice that 1.0 mill/kWh on the basis of average system marginal cost (~ 20 mills/kWh) approximates the five percent rule of the Merger Guidelines. The 0.5 mills/kWh deadband is considerably more strict.

Exhibit 20 illustrates the use of these deadbands in the analysis of competition for the marginal unit. In Exhibit 20A, we present a deadband (MC+d) when unit 3 of firm A (A3) is the marginal unit. Within this deadband, we find 6 other units, owned by firm A and three other generating companies (B, C, D). The units are A4, B2, B3, C4, C5, D7. Within the deadband as defined, these units will compete with A3 when it is the marginal unit. Their ability to compete will be determined by their capacity.

Exhibit 20B presents an alternative set of marginal unit characteristics with alternative implications regarding competition within the given deadband. In Exhibit 20B, the supply curve is more steep following unit A3 and fewer firms and units compete within the deadband -- specifically, A4 and B2.

[18] Of the 407 generating units in New England, the first 215 units (ordered by increasing dispatch cost) have low (less than 10 mills/kWh) dispatch costs and are considered to be baseload units. These consist of all hydroelectric units, all nuclear units and a group of refuse-fired units with dispatch costs less than 10 mills. The remaining 192 units - fossil-fuel and wood fired - are considered the set of units where a marginal unit would determine system price. Eighty four percent of the year - 7,391 hours out of 8,760 - the NEPOOL system dispatches units at costs at or above the marginal cost of the 216th unit, - i.e., the first "marginal unit".

Exhibit 20A. Demonstration of Marginal Unit Economics: Case I

Exhibit 20B. Demonstration of Marginal Unit Economics: Case II

2.2.4.2 Marginal Unit Analysis of 192 Potentially Marginal New England Units

The number of units within the two alternative deadbands for each of 192 generating units are tabulated using histograms in Exhibits 21 and 22. For example, for the 1 mill deadband, of the 192 markets defined (one for each of the units), the breakdown of the number of units, including the marginal unit, in the deadband (bin) is depicted in Exhibit 21. We find fifteen instances where only 1 unit, the marginal unit itself, was in the bin. In the remaining 177 instances, at least 2 units were in the bin. Of these 177, there were ten occurrences of a single entity controlling all of the units in the bin. Therefore, a monopoly on marginal unit generation exists for 17 (15 plus 2) of the 192 marginal generation markets for the 1 mil. deadband case.

Exhibit 23 and 24 illustrate the distribution of the total number of marginal dispatch hours per year across the different ownership concentration types. The exhibits also show the number of units in each ownership concentration category, as is Exhibits 21 and 22, but use a percentage indicator instead of an absolute reference. The exhibits illustrate the extent to which potential marginal unit markets in any given ownership concentration category are realized based on the number of hours the NEPOOL system dispatches units at the market's marginal cost.

Exhibit 21. Histogram of Number of Units in Each Marginal Unit Bin, 1 Mill Bin Size

Exhibit 22. Histogram of Number of Units in Each Marginal Unit Bin, 0.5 Mill Bin Size

Exhibit 23. Histogram of Percentage of Units and Hours in Each Marginal Unit Bin, 1 Mill Bin Size

Exhibit 24. Histogram of Percentage of Units and Hours in Each Marginal Unit Bin, 0.5 Mill Bin Size

The number of owners of competing generating units within the two alternative deadbands for each of the 192 marginal generating markets are tabulated using histograms in Exhibits 25 and 26. For example, Exhibit 25 illustrates that, in markets defined by the 1 mill/kWh deadband:

- 8.9 percent (17 of 192) of the markets contain only one competitor;
- 20.8 percent (40 of 192) contain two competitors;
- 16.1 percent (31 of 192) contain three competitors;
- 24.5 percent (47 of 192) contain four competitors; and
- 29.7 percent (57 of 192) contain five or more competitors.

The corresponding figures for the 0.5 mill deadband markets shown in Exhibit 24 are:

- 23.4 percent (45 of 192) of the markets contain only one competitor;
- 27.6 percent (53 of 192) contain two competitors;
- 20.3 percent (39 of 192) contain three competitors;
- 9.9 percent (19 of 192) contain four competitors; and
- 18.8 percent (36 of 192) contain five or more competitors.

Exhibit 25. Number of Competing Entities Across All Marginal Unit Bins, 1 Mill Bin Size

Exhibit 26. Number of Competing Entities Across All Marginal Unit Bins, 0.5 Mill Bin Size

In order to extrapolate these notions of competitiveness to the system as a whole, it is necessary to estimate the number of hours per year that each unit is considered the system marginal unit based on its dispatch cost and the value of system lambda. For the portion of the supply curve where the 192 marginal units lay, Exhibit 27 shows the number of hours that each unit (or units in the case of identical dispatch costs) was in the marginal dispatch bin in 1994. Exhibit 27 also distinguishes between 1994 hours in which the marginal unit generation market is served by a single entity (monopoly), two entities (duopoly), three entities, etc.

Exhibit 27. Distribution of All Marginal Dispatch Hours Over All Marginal Units, 1994, 1 Mill/kWh Deadband

Exhibit 28 is differs from Exhibit 27 only in the definition of the deadband used to define the marginal generation unit market. Compared to Exhibit 27, it illustrates the difference in levels of potential market power when the deadband is restricted to only 0.5 mills/kWh. It shows that a "tighter",more strict, definition of the marginal unit market would result in fewer numbers of units eligible to be in the marginal unit bin, hence a generally greater degree of generator concentration for any given marginal market.

Exhibit 28. Distribution of All Marginal Dispatch Hours Over All Marginal Units, 1994, 0.5 Mill/kWh Deadband

There are a few observations that can be made about Exhibits 27 and 28:

- For the 1 mill/kwh deadband, there are relatively few incidences of monopoly power, and those tend to occur at places on the supply curve where the unit is rarely the marginally dispatched unit.
- There are a few places on the supply curve where dispatch cost gaps exists such that the collection of marginal units at thosepoints are dispatched as marginal units for a relatively large number of hours per year. For example, there are three peaks of 490, 6.83 and 555 hours at the beginning portion of the supply curve.
- When shifting to the stricter deadband - 0.5 mills/kwh - a greater incidence of potential market power is observed.
- NUGs have marginal units at portions of the supply curve where many marginal hours are observed. This indicates that the NUGs have entered the market at points on the supply curve such that IOU market power has been diluted.

Exhibit 29 lists the 15 generation units that are the only units in their respective "markets" for marginal power under the 1 mill/kWh deadband scenario.

Exhibit 29. NEPOOL Units with Monopoly Power in Marginal Unit Market, 1 Mill Bin Case

2.2.5 Geographic/Economic Boundaries

The geographic boundaries of the NEPOOL market for electricity generation are the New England state borders. Excluded from the market are isolated islands (such as Block Island, Rhode Island) with self-contained generation systems, and a few areas of Maine served by independent entities (which purchase some energy from NEPOOL member systems). The geographic boundaries extend into Canada and New York State when imports and exports of electricity are considered. In the long-term, the geographic boundaries could conceivably extend beyond New York State and reach into the adjacent Mid-Atlantic Area (Pennsylvania, New Jersey, Maryland, Delaware, and Washington, DC) and possibly beyond, through an open-access transmission network.

The economic boundaries of the market, which are discussed in Section 3 of this report will be determined by the availability and cost of transmitting electricity.. For the most part, all of the current players within the NEPOOL geographic market are in the same economic market. This includes investor-owned utilities, municipal agencies, and non-utility generators. Future market players will include these entities plus new entrants such as supply aggregators, demand aggregators, financial exchanges (such as NYMEX) and supporting service entities, and additional suppliers such as non-utility generators and energy service companies.

The economic boundaries of the market are also conditioned by the costs of importing and exporting power, as discussed below.

2.2.6 Identification of Imports and Exports

Exhibits 1 and 2 of section 2.2.1 described in aggregate the amount of capacity and energy exchanges that occur between the New England region and the adjacent areas of New York State and Canada. The following Exhibit 30[19] provides additional detail on energy and capacity interchanges.

Exhibit 30. Imports and Exports of Power Into And Out Of NEPOOL System

The New York Power Pool and New Brunswick systems are directly connected to New England through the AC transmission network. Hydro-Quebec is connected primarily through a DC tie-line, which is electrically isolated from the Eastern North American Interconnection, of which NEPOOL is a part. A small capacity contract also exists between New England Electric System and Ontario Hydro.

2.2.7 Anticipated Changes in the Generation Market

2.2.7.1 Overview

The first table in the 1995 NEPOOL Forecast of Capacity, Energy, Loads and Transmission - 1995-2010 presents NEPOOL's forecast of total capacity, including utility generation, non-utility generation and net purchases from adjacent regions. Exhibit 31 shows the total capacity forecast for the region for the period 1995-2010.

Exhibit 31. NEPOOL Capacity Forecast, 1995-2010

2.2.7.2 Forecasted Retirements and Additions[20]

The major short-term generation market changes are the repowering of New England Electric System's Manchester Street Station, with a net increase of 316 MW (Summer) capacity and the June, 1998 completion of a 150 MW coal unit for the Taunton Municipal Lighting Unit as reported in the NEPOOL CELT report.

Medium-term pending changes include proposed capacity additions between 1999 and 2004 totalling approximately 385 MW (Summer), and planned retirements of 253 MW (which includes planned retirement of 223 MW of Wyman

[19] This exhibit reiterates information found in the NPCC report (1995), Item 2C.

[20] In addition to retirements and additions described here, there are Scheduled Reratings in 1995 with a net increase of 23 MW (summer capability), and in 2000 with a net decrease of 2.1 MW. There are also
two units scheduled for Deactivated Reserve status in 1996 and 2002, with a net decrease in summer capability of 20.1 MW. Finally, there are four thermal units currently on deactivated status that are scheduled to return to service in 2001 and 2002, increasing the summer capability by a total of 223.5 MW.

Station units, which are also included as possible life extension candidates under the proposed additions section).

Between 2007 and 2010, the current licenses for three major nuclear units - Connecticut and Maine Yankee, and Millstone 1, a total of 2,071 MW - expire.

References/Sources

North American Electric Reliability Council, Electricity Supply and Demand Database, 1995.

Department of Energy/Energy Information Administration, Electric Power Annual 1994, Volume II, November, 1995.

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The New England Power Pool Generation Task Force and NEPLAN Staff, 1995 Summary Of The Generation Task Force Long-Range Study Assumptions, June, 1995

NEPOOL System Diagram Transmission System Map, Spring, 1995.

Section 3.

ISSUES IN TRANSMISSION

Michael C. Caramanis

April, 1996

3. ISSUES IN TRANSMISSION

3.1 Background and Present Practice

Present Operation and Planning Practice

The six state region of New England is currently coordinated by NEPOOL whose members account for more than 95.5% of electric power production, import, and transmission. The electric bulk power facilities (i.e. generators, high voltage transmission lines and transformers) are operated today by NEPOOL as a single power system. This means that NEPOOL coordinates the dispatch of generators, the maintenance schedule of transmission and generation, and the sharing of reserves. The objective of the coordination is to minimize total operating costs and assure reliability, subject to commonly accepted rules that define the responsibilities of participants. Planning is also coordinated by NEPOOL and its aim is that New England's power resources remain consistent with the reliability criteria accepted by NEPOOL and the Northeast Power Coordinating Council (NPCC).

New England is a diverse region with both rural and dense urban characteristics. The rural north contributes 20% of the peak load in the summer and 25% in the winter. Transmission lines in the North are long and sparse whereas in the south they are short and dense. Although the total generating capacity is roughly located in proportion to load, diversity in the type of generation technology (relatively more hydroelectric and nuclear in the north) and transactions with neighboring utilities result in significant intra-New England power duration of variable magnitude, direction, and timing.

New England's bulk transmission system consists of 115kV, 230kV, and 345kV transmission lines. Interconnection ties consist of :

- two 345kV, one 230kV, one 138kV, and three 115 kV ties with New York
- One existing and one planned 345 kV tie with New Brunswick
- two HVDC interconnections with Quebec allowing 225MW imports at Highgate in Northern Vermont and non-simultaneous operation of either a 690 MW connection at Comerford in northern New Hampshire or a 2000 MW connection at Sandy Pond in eastern Massachusetts.

A number of bulk transmission interfaces within New England and between New England and neighboring regions have been identified as a sufficient set that needs to be monitored so that flows over each one do not exceed predetermined thresholds. These include 16 interfaces with power flow limits enforced for the purpose of avoiding thermal overloading of transmission system devices and an additional 14 interfaces with power flow limits enforced for the purpose of avoiding stability problems. Not all of the potentially limiting devices are included in these interfaces. Congestion may occur at a device that is electrically related to an interface. The interfaces have been selected so that observing flow limits for those interfaces implies that all related devices are not congested. More on the actual identity and ownership of the thermal and stability interfaces can be found later in this section.

Whereas it is generally possible to dispatch generation resources efficiently without running against the flow limits of the 16 thermal and 14 stability interfaces, it is occasionally required to engage in uneconomic or *out of merit order* dispatch to avert exceeding interface flow limits, and in rare cases it may be necessary to engage in rationing or emergency actions. NEPOOL is responsible for these actions at present. In the future, this function will either have to continue to be exercised by NEPOOL or an other Independent System Operator, and/or, pricing rules ought to be instituted to allow the market to assume at least some of these functions and internalize their costs.

With the exception of transmission problems during 1988 (discussed below) the transmission system in New England has been operating without major disruptions. Periodically conducted planning studies indicate that existing and planned resources are adequate to allow reliable and efficient operation without encountering unacceptable restrictions resulting from thermal or stability constraints of the transmission system[21].

Transmission Problems during 1988 and 1989 and their Mitigation

During 1988 and 1989, numerous incidences of generating capacity shortage coupled with transmission bottlenecks were observed. As documented further under subsection 3.3, generation shortages experienced during 1988 (Seabrook not in-line and severe outages including Pilgrim) were often too high for the transmission system to support the increase in transmission flows that would have been required to overcome local generating capacity shortfalls. The less than satisfactory condition was recognized as such and the following measures were taken[22]:

In the short term:

-A study conducted in 1988, recommended reactive compensation improvements of 760 kV of transformers (source October 5, 1988 memo from John Somonelli to NEPOOL Operations and Planning Committees) by 1993. These recommendations were implemented.

- transmission system operating criteria and guidelines were updated and revised (source NEPOOL 1992 Annual Report p 9).

-During 1989, additional 345 kV transmission lines were added in the greater Boston area, alterations were made to accommodate increased imports from Hydro Quebec on the Phase II facility, and 345 kV of transformers were added in southeastern Massachusetts. (source 1989 NEPOOL Annual Report).

In the long term:

-Generating capacity increased (for example, two 250 MW Ocean State units were installed by 1992 (source 91 Triennial report, p 36) and the Manchester Street units were repowered to provide an additional 3x164=492 MW of power by 1996, and

-new transmission facilities have been added (source 1994 Triennial report, executive summary, p 1).

The transmission system strengthening activities, implemented already or planned, appear to be indeed adequate. CRS 30 Load Power Factor surveys for years 1984 to 1994 were carefully

[21]The factual information in this subsection has been obtained from NEPOOL FERC Form No. 715, Annual Transmission Planning and Evaluation Report, April 1, 1995.

[22]Information reported here was obtained from New England Power Pool Triennial Review of Resource Adequacy, January 1991, and New England Power Pool Triennial Review of Transmission Reliability 1994-2000, September 22, 1994.

examined. The VAR deficiency in the Southeastern NEPOOL region projected in 1987 for 1988 were 181.2 MVars, although the actual deficiencies were lower. Given the action taken and the addition of transformers, subsequent Power Factor Surveys indicate the transmission system's condition to be consistent with NEPOOL reliability standards.

3.2 Transmission Ownership in New England

Table 3.1 presents the breakdown of ownership of transmission facilities in New England by dollar value and miles of transmission lines. It is immediately obvious that the pattern of ownership is characterized by substantial concentration with two entities holding more than 70% of the assets. In addition the regional concentration of ownership gives regional utilities monopolistic power over the transmission of electricity to, from, and through their current service territory. The current system of sharing resources must continue under a future where *retail wheeling* is widely practiced. Hence regulated transmission pricing and the coordination of transmission resources by an Independent System Operator are important considerations.

Table 3.2 below shows new transmission facilities planned for installation by the year 2000. These planned facilities have been shown in studies to be adequate for maintaining the reliability of the NPCC interconnected systems (Source 1994 Triennial report, Executive Summary, page 2).

3.3 Constraint Identification

A detailed list appended at the end of section 3 presents the thermal and stability interfaces used today by NEPOOL to monitor and control transmission power flows in order to avoid

Table 3.1 Ownership of Transmission Assets

	High Voltage	Low Voltage	Total	Percent Ownership High V	Low V	Total
Bangor Hydro Electric Company		25	25	0%	0%	0%
Boston Edison Company	179	254	433	9%	5%	6%
Town of Braintree Electric Light Department Company		9	9	0%	0%	0%
Central Main Power Company	184	909	1093	9%	18%	15%
Commonwealth Energy System Companies	63	92	155	3%	2%	2%
Connecticut Light and Power Company*	389	981	1370	19%	19%	19%
Eastern Utilities Associates Companies	68	185	253	3%	4%	4%
Fitchburg Gas and Electric Light Company		9	9	0%	0%	0%
Holyoke Gas and Electric Department		9	9	0%	0%	0%
Holyoke Water Power Company*		14	14	0%	0%	0%
New England Electric System Operating Companies	683	1382	2065	34%	27%	29%
Public Service Company of new Hampshire*	261	518	779	13%	10%	11%
Total Taunton Municipal Lighting Plant		2	2	0%	0%	0%
The United Illuminating Company	6	112	118	0%	2%	2%
Vermont Electric Power Company	85	301	386	4%	6%	5%
Western Massachusetts Electric Company*	105	265	370	5%	5%	5%
Totals	**2023**	**5067**	**7090**			
*Aggregated Northeast Utilities Companies	**755**	**1778**	**2533**	**37%**	**35%**	**36%**

Source: New England Power Pool "Pool Transmission Facilities" as of January 1, 1995 Approved March 3, 1995 congestion[23]. It also shows the utilities involved in the ownership of all or part of the interface lines.

Table 3.2 Major (230 kV and above) Transmission Facilities Planned to 2000. (Source NEPOOL 1994 Triennial Review of Transmission Reliability. Executive Summary, p1)

Major Transmission Facilities Planned to 2000

Inter-Area Transmission Facilities	
Second New Brunswick Tie	
(Orrington to Point Lepreau 345 kV Circuit #1)	1997
Transmission Facilities (230 kV and above)	
Bridgewater 345/115 kV Autotransformer #2	1994
Lowell Road 345/34.5 kV Transformer #1	1996
Ward Hill 345/115 kV Autotransformer #1	1997
Granite-Middlesex 230 kV Circuit #1	1998
Middlesex-Champlain 230 kV Circuit #1	1998
Champlain 230/115 kV Autotransformer #1	1998
Kingston St 345/115 kV Autotransformer #2	1998
Chester 345/115 kV Autotransformer #1	1999
Timber Swamp Road 345/34.5 kV Transformer #2	1999
Mystic-Kingston St. 345 kV Circuit #2	2000
Bourne-Barnstable 345 kV	2000

[23]Note that the limiting elements are not necessarily included in the interface but are electrically related.

The NEPOOL 1994 Triennial Review of Transmission Reliability 1994-2000, issued on September 22, 1994, documents that no transmission constraints are expected to be active with any significant frequency during the next few years. However, it is worth exploring what may happen under a capacity shortfall as, for example, the one that occurred in 1988. Table 3.4 presents the frequency and severity of actions taken to avoid system imbalances and potential blackouts. The severity of each capacity shortfall is gauged by the highest OP4 action taken. OP4 actions range from 1 (steam generation is raised to maximum claimed capability) to 15 (Radio and TV appeals for voluntary load curtailment). Whereas capacity shortfalls are often a combination of generation and transmission shortages, during 1988, in approximately half of the occasions of OP4 action implementation, transmission limitations played a significant role. In particular, the following interfaces were limiting (Source: E. K. Nielsen's memos to NEPOOL Operating Committee, 1988):

•CONVEX to REMVEC		16
•Northern NE to Southern NE	2	
• to Eastern REMVEC	8	
•REMVEC to CONVEX	1	
•Maine to New Hampshire	4	
•Pleasant Valley to Long Mountain 398 line	1	

Under a restructured future, a regulated Independent System Operator and market-based though regulated transmission-pricing options ought to be compatible with the necessary operating procedures (i.e. economically efficient actions must be taken to alleviate congestion and observe interface flow limits) at times of shortfall and also provide the right incentives for investment in adequate transmission resources and location of generation.

Transmission pricing ought to be allowed to reflect the marginal cost of maintaining interface flows within the desired limits. Whereas these costs are most of the time non-existent, pricing options that reveal them to transmission users and holders of transmission rights (for example long term contract holders for firm power transfers between two regions) appear necessary for efficient rationing during times of capacity shortfall. Since the exact time and location of a congestion occurrence is unpredictable, transmission price add-ons that become effective on relatively short notice (say 1 to 24 hours) may need to be considered.

In addition to congestion costs that are usually bursty, infrequent, unpredictable and whose magnitude fluctuates significantly from say 0 most of the time to more than one dollar per kWh at certain times and locations, there are also transmission costs associated with transmission line power losses. These costs may vary with space and time, but are much more predictable with a relatively smooth periodic behavior. These costs can be reflected in simpler transmission price structures also discussed below.

Transmission costs are considered next.

Table 3.4 Frequency of OP4 Actions and severity, 1983-1995
(Source NEPOOL Annual Reports, 1988 p. 12, 1990 p. 12, 1992 p. 9, 1993 p. 4, 1994 p. 8, 1995 p. 9)

Year	No of Implementations	Comments
1983	0	
1984	13	
1985	7	
1986	32	
1987	24	24% involved actions 12-15
1988	37	41% actions 12-15, frequent transmission limitations
1989	24	8% involved actions 12-15
1990	3	
1991	5	
1992	2	
1993	1	
1994	2	1 involved transmission limitation
1995	9	

3.4 Identification of cost conditions

Appendix B presents the theory of electricity marginal cost pricing and transmission pricing options. The various cost components are summarized in this section and are quantified to the extent possible given the available data.

Marginal transmission costs between two locations or busses on an electric system's network are defined as the change in the total operating cost of the system resulting from a unit increase in load (demand) at the consumption location, accompanied by a unit increase in generation at the supplying location. This cost can be generally composed to two components:

- the *cost of congestion*, i.e., the cost (benefit) of preventing (alleviating) interface flows from exceeding their limits as a result of the unit increases in demand and supply at the respective locations, or, in other words, the cost (benefit) of preventing (alleviating) transmission facility congestion, and

- the *cost of power losses*, i.e. the cost (benefit) of higher (lower) power losses resulting from the unit increases in demand and supply at the respective locations.

Each one of the cost components may be positive or negative since the simultaneous increase of demand and supply may increase or decrease losses and the tendency for line congestion.

Appendix B discusses the marginal cost of losses and congestion and elaborates on the contribution of individual transmission lines.

To comprehend the nature and behavior of transmission costs in New England at present, the order of magnitude of congestion and losses related costs are quantified.

Congestion Costs

Congestion costs are proportional to the severity of the effort required to sustain acceptable interface power flow limits. Fortunately high cost incidences are less frequent than low cost incidences. In order of increasing cost magnitude, the actions taken when transmission capacity (often a combination of generation and transmission) is a limiting factor in meeting demand, and an approximate estimate of frequency and cost magnitudes under current conditions is given below.

Table 3.5 Orders of Magnitude of Intra New England Transmission Congestion Marginal Costs under Current Conditions (See discussion below for justification)

Type of Action	Frequency	Appr. Cost
•Out of merit (i.e. uneconomical) dispatch of available generating capacity	less than 500 hrs/yr	1-10 mills/ kWH
•Operating Procedure No. 4 (OP4) Actions During a Capacity Deficiency	less than 100hrs/yr	$0.01-1.00/ kWH
•Operating Procedure No. 7 (OP7) Action in an Emergency	few times in 10 yrs	exceeds $1/ kWH

The frequency and cost figures reported above are discussed next.

Out of merit dispatch is resorted to infrequently under present conditions. Although we do not have an exact analysis for recent years, expert opinion (Ross McEacharn, January 23, 1996) suggests that it does not exceed 500 hours in a year. Regarding costs, the specific example of the Maine-New Hampshire interface was used as indicative. Expert opinion (Ross McEacharn, January 23, 1996) suggests that out of merit dispatch actions taken to sustain power flow limits over that interface are on the order of $150,000 per year resulting in an average cost of 1 mill/kWH of energy flowing over the line. The associated marginal costs depend on the proportion of a wheeling transaction that flows over the interface. Assuming that the additional cost of the unit dispatched out of merit is 1 cent per kWH, a range of proportions between 0.1 and 1.0 results in a corresponding marginal cost of 1 to 10 mills per marginal kWH of the transaction[24]. The sensitivity of interface power flows with respect to a particular wheeling transaction depends on the location of the supply and

[24]In theory, as shown in Appendix B, the marginal cost of wheeling may be a multiple of the cost differential in the out of merit dispatch. However, under current conditions, it appears that marginal transmission costs due to out of merit dispatch rarely exceed 2 cents per kWH.

consumption nodes of the transaction.

OP4 actions are listed in Table 3.6 (Source 1991 Triennial report, page 5)

OP4 actions are taken rather infrequently. In fact, with the exception of 1986-89, there have been few OP4 actions taken during the last few years. However, the experience gained in 1988 teaches us that OP4 actions may become necessary during a period of moderate capacity shortfalls. The cost of OP4 actions generally increases with the number assigned to each action. Table 3.6 below describes each of the 15 steps, ranging from the increase of steam generation to its maximum to curtailing dispatchable (i.e. interruptible) loads and finally to public appeals for voluntary load curtailment. Analysis of the details of each action (for example efficiency decline and increased variable O&M costs when generators are pushed to their maximum output, the opportunity cost of activating interruptible contracts, etc.) can yield an associated cost. Whereas, we did not engage into such a detailed analysis, the range of costs from one cent to one dollar is generally appropriate.

OP7 action costs are estimated in excess of $1/ kWH as they are related to loss of service and electricity rationing coupled with a significant chance that the system will collapse.

Table 3.6 OP4 Actions During A Capacity Deficiency (Source 1991 NEPOOL Triennial Review of Resource Adequacy)

NEPEX Operating Procedure No. 4

Action During A Capacity Deficiency

Action	Procedure	Effect of Procedure	Estimated Value to NEPOOL (MW)*
1	Steam generation to maximum Claimed Capability	Increase capacity	130
2	ICU generation to Maximum Claimed Capability	Increase capacity	50
3	Curtail NEPOOL dispatchable loads - Block E	Load relief	2
4	Curtail NEPOOL dispatchable loads - Block D	Load relief	2
5	Curtail NEPOOL dispatchable loads - Block C	Load relief	10
6	Purchase emergency capacity and/or energy	Increase capacity	Varies
7	Curtail NEPOOL dispatchable loads - Block B	Load relief	50
8	Curtail NEPOOL dispatchable loads - Block A	Load relief	60
9	Voluntary load curtailment of NEPOOL participants facilities	Load relief	40
10	Request customer generation contractually available to NEPOOL participants during a capacity deficiency	Increase capacity	55
11	Allow 30 minute reserve to go to zero (0)	Load relief	Varies
12	Implement a 5% voltage reduction requiring more than 10 minutes	Load relief	50
13	Implement a 5% voltage reduction requiring 10 minutes or less	Load relief	340
14	Request customer generation not contractually available to NEPOOL participants	Increase capacity	45
15	Voluntary load curtailment from large industrial and commercial customers	Load relief	190
16	Radio and TV appeals for voluntary load curtailment	Load relief	200

*Estimated Value to NEPOOL is based on a 20,000 MW system load.

Cost of Power Losses

Whereas line losses are a function of the load/generation pattern and this pattern changes over time, the change is rather periodic and generally predictable. It is therefore possible to describe the behavior of the losses component of transmission costs in terms of *typical* loss penalty factors which are independent of the time varying system marginal cost (or system lambda). The loss penalty factors are used today by NEPOOL in economic dispatch. The factors adjust the marginal cost of specific generators to reflect their contribution to line losses. The cost of losses from generation at a specific location (i.e. an injection into the transmission grid at a specific point) is thus described as a proportion of the system marginal cost at that time.

The cost of power losses in New England is quantified in the table below.

Table 3.7 Geographic distribution of Loss factors at Low, Medium, and High Load Conditions (source Ross McEacharn, January 23, 1996)

Table to be inserted in later version

To interpret the information of table 3.7 note that penalty factor of 1.05 at location A and 0.97 at location B means that, in the absence of transmission constraints, it is possible to substitute 1.05 kW of generation at location A with 0.97 kW of generation at location B, and, that, if this happens, the system line losses will decrease by 0.08 kW. In other words, generation at location A is equivalent (i.e. equally cost effective) to generation at location B as long as the variable cost at A and B, say C_A and C_B are such that $1.05xC_A=0.97xC_B$, or $C_A/C_B=0.97/1.05$, or roughly, C_A is 8% lower than C_B.

The penalty factors of units that are on the margin most of the time (i.e. units with marginal operating cost around 2.5 cents/kWH), indicate that during low load conditions, nodal marginal cost differences do not exceed 8% of the system marginal cost, and hence, the losses component of intra-region transmission costs also does not exceed 8% of the system marginal cost. At high load conditions, the difference increases to a maximum of 12%. Given that marginal generating cost (system lambda) is generally in the vicinity of 2.5 cents per kWH for 90% of the time, we can conclude that most of the time:

-3 mills/kWH $\leq$ Intra New Eng. Transm Cost Due to Line Losses $\leq$ +3 mills /kWH

It is important to note that the geographic variability of penalty factors reveals an interesting pattern consisting of high losses-costs in Maine, and lower in the south, with certain regions exhibiting rather uniform penalty factor values.

3.5 Implications for Desired Pricing

The facts presented above suggests that a zonal transmission pricing approach that charges predetermined time-of-day transmission rates for wheeling electricity from a generator in one region to a consumer in another, can capture the spatial and temporal variability of the losses component of transmission costs.

As discussed in Appendix B, the zonal pricing method is amenable to regulation of revenues which will be necessary given the economies of scale in transmission that present the establishment of a competitive market in transmission services. Relevant experience in England, indicate that a regulated transmission entity can be provided with appropriate incentives to invest in and maintain the transmission system so as to eliminate opportunities for regional generators to acquire significant market power as a result of frequent congestion occurrences.

Table 3.3 16 thermal , 14 stability NEPOOL limiting bulk Transmission Interfaces (source NEPOOL FERC Form No. 715, Annual Transmission Planning and Evaluation Report, April 1, 1995) and the utilities owning the busses at each end of each line comprising the interface (NEPOOL FERC Form No. 715, April 1, 1995, and NEPOOL System Diagram, Spring 1995).

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: Boston Import

Plant:	Tewskbury	->	East Tewksbury #2	**kV:**	115
Utility:	New England Power Company	->	New England Power Company		
Location:	m-5	->	n-5		
Plant:	Dracut Jct.	->	West Methuen	**kV:**	115
Utility:	junction	->	New England Power Company		
Location:	m-5	->	n-5		
Plant:	Tewksbury	->	North Woburn Tap	**kV:**	115
Utility:	New England Power Company	->	Boston Edison Company		
Location:	m-5	->	n-5		
Plant:	Tewksbury	->	East Tewksbury #1	**kV:**	115
Utility:	New England Power Company	->	New England Power Company		
Location:	m-5	->	n-5		
Plant:	Medway	->	Sherborn	**kV:**	115
Utility:	Boston Edison Company	->	Boston Edison Company		
Location:	m-8	->	m-7		
Plant:	West Walpole	->	Dover	**kV:**	115
Utility:	Boston Edison Company	->	Boston Edison Company		

Location: m-8 -> n-7

Plant: Medway -> Framingham **kV:** 115

Utility: Boston Edison Company -> Boston Edison Company

Location: m-8 -> m-7

Plant: Northboro Rd. -> West Framnigham **kV:** 115

Utility: New England Power Company -> Boston Edison Company

Location: l-7 -> l-7

Plant: West Medway -> Waltham **kV:** 230

Utility: Boston Edison Company -> Boston Edison Company

Location: l-8 -> m-6

OOL Limiting Bulk Transmission Interfaces

16-Apr-96

Plant: West Medway -> Framingham **kV:** 230

Utility: Boston Edison Company -> Boston Edison Company

Location: l-8 -> m-7

Plant: Sandy Pond -> Tewksbury **kV:** 345

Utility: New England Power Company -> New England Power Company

Location: l-5 -> m-5

Plant: Seabrook -> Tewksbury **kV:** 345

Utility: Northeast Utilities -> New England Power Company

Location: p-4 -> m-5

Plant: Tewksbury -> Billerica **kV:** 115

Utility: New England Power Company -> New England Power Company

Location: m-5 -> m-5

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: Connecticut Import

Plant:	Ludlow	->	Meekville Jct.	**kV:**	345
Utility:	Northeast Utilities	->	junction		
Location:	g-7	->	f-9		
Plant:	So. Agawam Jct.	->	North Bloomfield	**kV:**	115
Utility:	junction	->	Northeast Utilities		
Location:	e-8	->	e-9		
Plant:	Southwick	->	North Bloomfield	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	d-9	->	e-9		
Plant:	Wood River	->	Mystic	**kV:**	115
Utility:	New England Power Company	->	Northeast Utilities		
Location:	j-12	->	j-12		
Plant:	Northport	->	Norwalk Harbor	**kV:**	138
Utility:	off map	->	Northeast Utilities		
Location:	a-13	->	a-13		
Plant:	Pleasant Valley	->	Long Mountain	**kV:**	345
Utility:	off map	->	Northeast Utilities		
Location:	a-11	->	a-11		
Plant:	Sherman	->	Card	**kV:**	345
Utility:	Eastern Utilities Associates	->	Northeast Utilities		

Location:	k-9	->	h-10	

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: Connecticut Export

Plant:	Mystic	->	Wood River	**kV:**	115
Utility:	Northeast Utilities	->	New England Power Company		
Location:	j-12	->	j-12		
Plant:	North Bloomfield	->	So. Agawam Jct.	**kV:**	115
Utility:	Northeast Utilities	->	junction		
Location:	e-9	->	e-8		
Plant:	Norwalk Harbor	->	Northport	**kV:**	138
Utility:	Northeast Utilities	->	off map		
Location:	a-13	->	a-13		
Plant:	Meekville Jct.	->	Ludlow	**kV:**	345
Utility:	junction	->	Northeast Utilities		
Location:	f-9	->	g-7		
Plant:	North Bloomfield	->	Southwick	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	e-9	->	d-9		
Plant:	Card	->	Sherman	**kV:**	345
Utility:	Northeast Utilities	->	Eastern Utilities Associates		
Location:	h-10	->	k-9		
Plant:	Long Mountain	->	Pleasant Valley	**kV:**	345

Utility: Northeast Utilities	->	off map		
Location: a-11	->	a-11		

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: CONVEX-REMVEC

Plant: Montague	->	Mass Yankee	**kV:**	115
Utility: Northeast Utilities	->	New England Power Company		
Location: f-6	->	c-5		
Plant: Ludlow	->	Carpenter Hill	**kV:**	345
Utility: Northeast Utilities	->	New England Power Company		
Location: g-7	->	h-8		
Plant: Northfield	->	VT Yankee	**kV:**	345
Utility: Northeast Utilities	->	Vermont Electric Power Company		
Location: g-5	->	g-5		
Plant: Card	->	Sherman	**kV:**	345
Utility: Northeast Utilities	->	Eastern Utilities Associates		
Location: h-10	->	k-9		
Plant: Mystic	->	Wood River	**kV:**	115
Utility: Northeast Utilities	->	New England Power Company		
Location: j-12	->	j-12		
Plant: Ludlow	->	Palmer	**kV:**	115
Utility: Northeast Utilities	->	New England Power Company		
Location: g-7	->	h-7		

Plant:	Lanesboro	**->** Adams		**kV:**	115
Utility:	not on map	**->**	New England Power Company		
Location:	not on map	**->**	a-6		

Plant:	Montague	**->** Cabot Tap		**kV:**	115
Utility:	Northeast Utilities	**->**	Northeast Utilities		
Location:	f-6	**->**	f-6		

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: Maine Yankee-South

Plant:	Main Yankee	**->** Buxton		**kV:**	345
Utility:	Central Main Power Company	**->**	Central Main Power Company		
Location:	o-2	**->**	o-3		

Plant:	Main Yankee	**->** Surowiec		**kV:**	345
Utility:	Central Main Power Company	**->**	Central Main Power Company		
Location:	o-2	**->**	o-3		

Plant:	Mason	**->** Mason		**kV:**	460
Utility:	Central Main Power Company	**->**	Central Main Power Company		
Location:	o-2	**->**	o-2		

Thermal Interfaces: Maine-New Hampshire

Plant:	Buxton	**->** Deerfield		**kV:**	345
Utility:	Central Main Power Company	**->**	Northeast Utilities		
Location:	o-3	**->**	o-4		

Plant: Buxton	->	Scobie	**kV:**	345
Utility: Central Main Power Company	->	Northeast Utilities		
Location: o-3	->	n-4		
Plant: Quacker Hill	->	Three Rivers	**kV:**	115
Utility: Central Main Power Company	->	Northeast Utilities		
Location: p-3	->	p-4		
Plant: Maguire	->	Three Rivers	**kV:**	115
Utility: Central Main Power Company	->	Northeast Utilities		
Location: p-3	->	p-4		

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: New England - New York

Plant: Berkshire	->	Alps	**kV:**	345
Utility: Northeast Utilities	->	off map		
Location: b-6	->	a-6		
Plant: Blissville	->	Whitehall	**kV:**	115
Utility: Vermont Electric Power Company	->	off map		
Location: a-3	->	a-3		
Plant: Norwalk Harbor	->	Northport	**kV:**	138
Utility: Northeast Utilities	->	off map		
Location: a-13	->	a-13		
Plant: Bennington	->	Hoosick	**kV:**	115

Utility:	Vermont Electric Power Company	->	off map		
Location:	a-5	->	a-5		
Plant:	South Hero	->	Plattsburgh	**kV:**	115
Utility:	Vermont Electric Power Company	->	off map		
Location:	a-1	->	a-1		
Plant:	Long Mountain	->	Pleasant Valley	**kV:**	345
Utility:	Northeast Utilities	->	off map		
Location:	a-11	->	a-11		
Plant:	Bear Swamp	->	Rotterdam	**kV:**	230
Utility:	New England Power Company	->	off map		
Location:	b-5	->	a-5		

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: New York - New England

Plant:	Hoosick	->	Bennington	**kV:**	115
Utility:	off map	->	Vermont Electric Power Company		
Location:	a-5	->	a-5		
Plant:	Alps	->	Berkshire	**kV:**	345
Utility:	off map	->	Northeast Utilities		
Location:	a-6	->	b-6		
Plant:	Northport	->	Norwalk Harbor	**kV:**	138
Utility:	off map	->	Northeast Utilities		
Location:	a-13	->	a-13		

Plant: Rotterdam -> Bear Swamp **kV:** 230
Utility: off map -> New England Power Company
Location: a-5 -> b-5

Plant: Plattsburgh -> South Hero **kV:** 115
Utility: off map -> Vermont Electric Power Company
Location: a-1 -> a-1

Plant: Pleasant Valley -> Long Mountain **kV:** 345
Utility: off map -> Northeast Utilities
Location: a-11 -> a-11

Plant: Whitehall -> Blissville **kV:** 115
Utility: off map -> Vermont Electric Power Company
Location: a-3 -> a-3

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: North-South

Plant: Comerford -> Tewksbury **kV:** 230
Utility: New England Power Company -> New England Power Company
Location: h-2 -> m-5

Plant: Scobie -> Sandy Pond **kV:** 345
Utility: Northeast Utilities -> New England Power Company
Location: n-4 -> l-5

Plant: VT Yankee -> Northfield **kV:** 230
Utility: Vermont Electric Power Company -> Northeast Utilities

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NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: Northern Maine Import

Plant:	surowiec	->	crowleys	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	o-3	->	n-2		
Plant:	maxcys	->	winslow	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	p-2	->	o-1		
Plant:	maxcys	->	farmingdale	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	p-2	->	o-2		
Plant:	maxcys	->	rice rips	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	p-2	->	o-1		
Plant:	surowiec	->	raymond	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	o-3	->	m-3		
Plant:	surowiec	->	gulf	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	o-3	->	n-2		
Plant:	bucksport	->	detroit	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		

Location:	o-1	->	o-1		
Plant:	maxcys	->	augusta	**kV:**	115
Utility:	Central Main Power Company	->	Central Main Power Company		
Location:	p-2	->	o-2		

NEPOOL Limiting Bulk Transmission Interfaces

16-Apr-96

Thermal Interfaces: Norwalk - Stamford Import

Plant:	Pequonnock	->	RESCO Tap	**kV:**	115
Utility:	United Illuminating Company	->	Non-Nepool		
Location:	b-13	->	b-13		
Plant:	Trumbull Jct.	->	Weston	**kV:**	115
Utility:	junction	->	Northeast Utilities		
Location:	b-13	->	b-13		
Plant:	Trumbull Jct.	->	Old Town	**kV:**	115
Utility:	junction	->	United Illuminating Company		
Location:	b-13	->	b-13		
Plant:	Northport	->	Norwalk Harbor	**kV:**	138
Utility:	off map	->	Northeast Utilities		
Location:	a-13	->	a-13		
Plant:	Plumtree	->	Ridgefield Jct.	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	a-12	->	a-12		
Plant:	Pequonnock	->	Darien	**kV:**	115

Utility:	United Illuminating Company	->	Northeast Utilities		
Location:	b-13	->	a-13		

NEPOOL Limiting Bulk Transmission Interfaces

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Thermal Interfaces: REMVEC-CONVEX

Plant:	Palmer	->	Ludlow	**kV:**	115
Utility:	New England Power Company	->	Northeast Utilities		
Location:	h-7	->	g-7		
Plant:	Cabor Tap	->	Montague	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	f-6	->	f-6		
Plant:	Mass Yankee	->	Montague	**kV:**	115
Utility:	New England Power Company	->	Northeast Utilities		
Location:	c-5	->	f-6		
Plant:	Wood River	->	Mystic	**kV:**	115
Utility:	New England Power Company	->	Northeast Utilities		
Location:	j-12	->	j-12		
Plant:	Sherman	->	Card	**kV:**	345
Utility:	Eastern Utilities Associates	->	Northeast Utilities		
Location:	k-9	->	h-10		
Plant:	VT Yankee	->	Northfield	**kV:**	345
Utility:	Vermont Electric Power Company	->	Northeast Utilities		

Location: g-5 -> g-5

Plant: Carpenter Hill -> Ludlow **kV:** 345
Utility: New England Power Company -> Northeast Utilities
Location: h-8 -> g-7

Plant: Adams -> Lanesboro **kV:** 115
Utility: New England Power Company -> ???
Location: a-6 -> ???

NEPOOL Limiting Bulk Transmission Interfaces

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Thermal Interfaces: Sandy Pond-South

Plant: Sandy Pond -> Milbury **kV:** 345
Utility: New England Power Company -> New England Power Company
Location: l-5 -> j-7

Plant: Sandy Pond -> Sandy Pond **kV:** 460
Utility: New England Power Company -> New England Power Company
Location: l-5 -> l-5

Plant: Sandy Pond -> Millbury **kV:** 345
Utility: New England Power Company -> New England Power Company
Location: l-5 -> j-7

Plant: Sandy Pond -> Sandy Pond **kV:** 460
Utility: New England Power Company -> New England Power Company
Location: l-5 -> l-5

Plant:	Sandy Pond	->	Tewksbury	**kV:**	345
Utility:	New England Power Company	->	New England Power Company		
Location:	l-5	->	m-5		

NEPOOL Limiting Bulk Transmission Interfaces

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Thermal Interfaces: Southeast Massachusetts Export

Plant:	Carver	->	W. Walpole	**kV:**	345
Utility:	Commonwealth Energy System	->	Boston Edison Company		
Location:	o-10	->	m-8		
Plant:	Bridgewater	->	West Medway	**kV:**	345
Utility:	Eastern Utilities Associates	->	Boston Edison Company		
Location:	o-10	->	l-8		
Plant:	Holbrook	->	W. Walpole	**kV:**	345
Utility:	Boston Edison Company	->	Boston Edison Company		
Location:	o-8	->	m-8		
Plant:	Walpole	->	W. Walpole	**kV:**	115
Utility:	Boston Edison Company	->	Boston Edison Company		
Location:	n-8	->	m-8		
Plant:	Somerset	->	Pawtucket	**kV:**	115
Utility:	Eastern Utilities Associates	->	Eastern Utilities Associates		
Location:	n-11	->	l-11		
Plant:	Somerset	->	Swansea	**kV:**	115
Utility:	Eastern Utilities Associates	->	Eastern Utilities Associates		

Location: n-11	->	m-11		
Plant: Somerset	->	Phillipsdale	**kV:**	115
Utility: Eastern Utilities Associates	->	New England Power Company		
Location: n-11	->	l-11		
Plant: Walpole	->	W. Walpole	**kV:**	115
Utility: Boston Edison Company	->	Boston Edison Company		
Location: n-8	->	m-8		

NEPOOL Limiting Bulk Transmission Interfaces

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Thermal Interfaces: Southeast Massachusetts/Rhode Island Export

Plant: Sherman	->	Card	**kV:**	345
Utility: Eastern Utilities Associates	->	Northeast Utilities		
Location: k-9	->	h-10		
Plant: West Medway	->	West Medway	**kV:**	345
Utility: Boston Edison Company	->	Boston Edison Company		
Location: l-8	->	l-8		
Plant: Whitins Pond	->	Millbury	**kV:**	115
Utility: New England Power Company	->	New England Power Company		
Location: k-9	->	j-7		
Plant: Depot	->	Millbury	**kV:**	115
Utility: New England Power Company	->	New England Power Company		
Location: k-7	->	j-7		

Plant: Depot	-> Millbury		**kV:**	115
Utility: New England Power Company	->	New England Power Company		
Location: k-7	->	j-7		
Plant: Medway	-> Sherborn		**kV:**	115
Utility: Boston Edison Company	->	Boston Edison Company		
Location: m-8	->	m-7		
Plant: West Medway	-> West Medway		**kV:**	345
Utility: Boston Edison Company	->	Boston Edison Company		
Location: l-8	->	l-8		
Plant: West Medway	-> Millbury		**kV:**	345
Utility: Boston Edison Company	->	New England Power Company		
Location: l-8	->	j-7		
Plant: W. Walpole	-> Dover		**kV:**	115
Utility: Boston Edison Company	->	Boston Edison Company		
Location: m-8	->	n-7		

NEPOOL Limiting Bulk Transmission Interfaces

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Plant: Wood River	-> Mystic		**kV:**	115
Utility: New England Power Company	->	Northeast Utilities		
Location: j-12	->	j-12		
Plant: Whitins Pond	-> Milbury		**kV:**	115
Utility: New England Power Company	->	New England Power Company		
Location: k-9	->	j-7		
Plant: West Medway	-> Millbury		**kV:**	345

Utility:	Boston Edison Company	->	New England Power Company		
Location:	l-8	->	j-7		

NEPOOL Limiting Bulk Transmission Interfaces

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Thermal Interfaces: Southern Connecticut-Import

Plant:	Frost Bridge	->	Baldwin Tap	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	c-10	->	d-12		
Plant:	Southington	->	Glen Lake	**kV:**	115
Utility:	Northeast Utilities	->	junction		
Location:	e-10	->	e-12		
Plant:	Frost Bridge	->	Shaws Hill	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	c-10	->	c-11		
Plant:	East Shore	->	East Shore #2	**kV:**	460
Utility:	United Illuminating Company	->	United Illuminating Company		
Location:	f-13	->	f-13		
Plant:	Frost Bridge	->	Carmel	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	c-10	->	b-10		
Plant:	Frost Bridge	->	Freight	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	c-10	->	d-11		

Plant:	Southington	->	Lucchini	**kV:**	115
Utility:	Northeast Utilities	->	junction		
Location:	e-10	->	e-11		
Plant:	Southington	->	Wallingfor Jct.	**kV:**	115
Utility:	Northeast Utilities	->	Non-Nepool		
Location:	e-10	->	e-12		
Plant:	East Shore	->	East Shore #1	**kV:**	460
Utility:	United Illuminating Company	->	United Illuminating Company		
Location:	f-13	->	f-13		

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Plant:	Plum Tree	->	Plum Tree	**kV:**	460
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	a-12	->	a-12		
Plant:	Plum Tree	->	Plum Tree	**kV:**	460
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	a-12	->	a-12		
Plant:	Northport	->	Norwalk Harbor	**kV:**	138
Utility:	off map	->	Northeast Utilities		
Location:	a-13	->	a-13		
Plant:	Green Hill	->	Branford	**kV:**	115
Utility:	Northeast Utilities	->	Northeast Utilities		
Location:	g-12	->	f-13		

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: Comerford-South MVA

Plant: Comerford -> Tewksbury **kV:** 230

Utility: New England Power Company -> New England Power Company

Location: h-2 -> m-5

Plant: Comerford -> Dunbarton **kV:** 230

Utility: New England Power Company -> tap

Location: h-2 -> l-3

Stability Interfaces: Comerford/Moore-South MW

Plant: Comerford -> Granite **kV:** 230

Utility: New England Power Company -> Vermont Electric Power Company

Location: h-2 -> e-2

Plant: Comerford -> Tewksbury **kV:** 230

Utility: New England Power Company -> New England Power Company

Location: h-2 -> m-5

Plant: Comerford -> Dunbarton **kV:** 230

Utility: New England Power Company -> tap

Location: h-2 -> l-3

Plant: U199 Tap -> Woodstock **kV:** 115

Utility: Northeast Utilities -> Northeast Utilities

Location: k-3 -> k-3

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: Hydro Quebec - New England

Plant:	Radisson	->	Nicolet-Sany Pond Hvdc	**kV:**	0
Utility:	New England Power Company	->	New England Power Company		
Location:	l-5	->	l-5		
Plant:	Highgate	->	back-to-back Hvdc	**kV:**	0
Utility:	Vermont Electric Power Company	->	Vermont Electric Power Company		
Location:	a-1	->	a-1		

Stability Interfaces: Maine - New Hampshire

Plant:	Buxton	->	Deerfield	**kV:**	345
Utility:	Central Main Power Company	->	Northeast Utilities		
Location:	o-3	->	o-4		
Plant:	Buxton	->	Scobie	**kV:**	345
Utility:	Central Main Power Company	->	Northeast Utilities		
Location:	o-3	->	n-4		
Plant:	Quaker Hill	->	Three Rivers	**kV:**	115
Utility:	Central Main Power Company	->	Northeast Utilities		
Location:	p-3	->	p-4		
Plant:	Maguire	->	Three Rivers	**kV:**	115
Utility:	Central Main Power Company	->	Northeast Utilities		
Location:	p-3	->	p-4		

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: New Brunswick - New England

Plant:	Keswick	->	Chester-Orrington	**kV:**	345
Utility:	off map	->	Bangor Hydro-Electric Company		
Location:	q-1	->	q-1		

Stability Interfaces: New England - New Brunswick

Plant:	Orrington	->	Chester-Keswick	**kV:**	345
Utility:	Bangor Hydro-Electric Company	->	Bangor Hydro-Electric Company		
Location:	q-1	->	q-1		

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: New England - New York

Plant:	Bennington	->	Hoosick	**kV:**	115
Utility:	Vermont Electric Power Company	->	off map		
Location:	a-5	->	a-5		
Plant:	Norwalk Harbor	->	Northport	**kV:**	138
Utility:	Northeast Utilities	->	off map		
Location:	a-13	->	a-13		

Plant:	Long Mountain	->	Pleasant Valley	**kV:**	345
Utility:	Northeast Utilities	->	off map		
Location:	a-11	->	a-11		
Plant:	South Hero	->	Plattsburgh	**kV:**	115
Utility:	Vermont Electric Power Company	->	off map		
Location:	a-1	->	a-1		
Plant:	Blissville	->	Whitehall	**kV:**	115
Utility:	Vermont Electric Power Company	->	off map		
Location:	a-3	->	a-3		
Plant:	Berkshire	->	Alps	**kV:**	345
Utility:	Northeast Utilities	->	off map		
Location:	b-6	->	a-6		
Plant:	Bear Swamp	->	Rotterdam	**kV:**	230
Utility:	New England Power Company	->	off map		
Location:	b-5	->	a-5		

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: New England East-West

Plant:	Comerford	->	Granite	**kV:**	230
Utility:	New England Power Company	->	Vermont Electric Power Company		
Location:	h-2	->	e-2		
Plant:	Sherman	->	Card	**kV:**	345
Utility:	Eastern Utilities Associates	->	Northeast Utilities		

Location: k-9 -> h-10

Plant: Millbury -> Carpenter Hill **kV:** 345
Utility: New England Power Company -> New England Power Company
Location: k-7 -> h-8

Plant: Scobie -> Amherst **kV:** 345
Utility: Northeast Utilities -> Northeast Utilities
Location: n-4 -> j-4

Plant: Pratts Jct. -> Bear Swamp **kV:** 230
Utility: New England Power Company -> New England Power Company
Location: k-5 -> b-5

Plant: Webster -> North Road **kV:** 115
Utility: Northeast Utilities -> Northeast Utilities
Location: k-3 -> h-3

Plant: Greggs -> Jackman **kV:** 115
Utility: Northeast Utilities -> Northeast Utilities
Location: k-4 -> j-4

Plant: Pratts Jct. -> Flagg Pond **kV:** 115
Utility: New England Power Company -> UNITIL
Location: k-5 -> i-5

Plant: Pratts Jct. -> Litchfield **kV:** 115
Utility: New England Power Company -> New England Power Company
Location: k-5 -> j-5

NEPOOL Limiting Bulk Transmission Interfaces

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Plant: Millbury -> Webster St. **kV:** 115

Utility: Νεω_Ενγλανδ_Ποωερ_Χομπανψ **->**
Νεω_Ενγλανδ_Ποωερ_Χομπανψ

_Λοχατιον: κ-7 **->**
φ-7

Πλαντ: Μιλλβυρψ **->** Βαρρε κς:
115

Υτιλιτψ: New England Power Company **->**
nd Power Company

Location: k-7 **->**
h-6

Plant: Millbury **->** Oxford **kV:** 115

Utility: New England Power Company **->**
nd Power Company

Location: k-7 **->**
h-8

Plant: Wood River **->** Mystic **kV:** 115

Utility: New England Power Company **->**
Northeast Utilities

Location: j-12 **->**
j-12

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: New York - New England

Plant: Northport **->** Norwalk Harbor **kV:** 138

Utility: off map **->**
Northeast Utilities

Location: a-13 **->**
a-13

Plant: Hoosick **->** Bennington **kV:** 115

Utility: off map **->**

ic Power Company			
Location: a-5	**->**		
a-5			
Plant: Rotterdam	**->** Bear Swamp	**kV:**	230
Utility: off map	**->**		
nd Power Company			
Location: a-5	**->**		
b-5			
Plant: Pleasant Valley	**->** Long Mountain	**kV:**	345
Utility: off map	**->**		
Northeast Utilities			
Location: a-11	**->**		
a-11			
Plant: Plattsburgh	**->** South Hero	**kV:**	115
Utility: off map	**->**		
ic Power Company			
Location: a-1	**->**		
a-1			
Plant: Alps	**->** Berkshire	**kV:**	345
Utility: off map	**->**		
Northeast Utilities			
Location: a-6	**->**		
b-6			
Plant: Whitehall	**->** Blissville	**kV:**	115
Utility: off map	**->**		
ic Power Company			
Location: a-3	**->**		
a-3			

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Stability Interfaces: Northern New England Scobie + 394

Plant: Seabrook -> Scobie **kV:** 345

Utility: Northeast Utilities ->
Northeast Utilities

Location: p-4 ->
n-4

Plant: Buxton -> Scobie **kV:** 345

Utility: Central Main Power Company ->
Northeast Utilities

Location: o-3 ->
n-4

Plant: Seabrook -> Tewksbury **kV:** 345

Utility: Northeast Utilities ->
nd Power Company

Location: p-4 ->
m-5

Plant: Deerfield -> Scobie **kV:** 345

Utility: Northeast Utilities ->
Northeast Utilities

Location: o-4 ->
n-4

Stability Interfaces: Sandy Pond Export

Plant: Sandy Pond -> Nicolet-Radison Hvdc **kV:** 0

Utility: New England Power Company ->
nd Power Company

Location: l-5 ->
l-5

Stability Interfaces: Sandy Pond Import

Plant: Radisson	-> Nicolet-Sany Pond Hvdc	**kV:**	0
Utility: New England Power Company	->		
nd Power Company			
Location: l-5	->		
l-5			

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Stability Interfaces: Seabrook - South

Plant: Seabrook	-> Tewksbury	**kV:**	345
Utility: Northeast Utilities	->		
nd Power Company			
Location: p-4	->		
m-5			
Plant: Seabrook	-> Scobie	**kV:**	345
Utility: Northeast Utilities	->		
Northeast Utilities			
Location: p-4	->		
n-4			

NEPOOL Limiting Bulk Transmission Interfaces

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Stability Interfaces: Southeast Massachusetts/Rhode Island Export

Plant: Whitins Pond	-> Millbury	**kV:**	115
Utility: New England Power Company	->		
nd Power Company			
Location: k-9	->		
j-7			

Plant: Depot -> Millbury **kV:** 115

Utility: New England Power Company ->
nd Power Company

Location: k-7 ->
j-7

Plant: Sherman -> Card **kV:** 345

Utility: Eastern Utilities Associates ->
Northeast Utilities

Location: k-9 ->
h-10

Plant: Walpole -> Dover **kV:** 115

Utility: Boston Edison Company ->
n Edison Company

Location: n-8 ->
n-7

Plant: Medway -> Sherborn **kV:** 115

Utility: Boston Edison Company ->
n Edison Company

Location: m-8 ->
m-7

Plant: West Medway -> West Medway **kV:** 460

Utility: Boston Edison Company ->
n Edison Company

Location: l-8 ->
l-8

Plant: West Medway -> West Medway **kV:** 460

Utility: Boston Edison Company ->
n Edison Company

Location: l-8 ->
l-8

Plant: West Medway -> Millbury **kV:** 345

Utility: Boston Edison Company ->
nd Power Company

Location: l-8 ->
j-7

Plant: Whitins Pond -> Milbury **kV:** 115

Utility: New England Power Company ->
nd Power Company

Location: k-9 ->
j-7

NEPOOL Limiting Bulk Transmission Interfaces

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Plant:	Wood River	-> Mystic	**kV:**	115
Utility: Northeast Utilities	New England Power Company	->		
Location: j-12	j-12	->		
Plant:	Depot	-> Millbury	**kV:**	115
Utility: nd Power Company	New England Power Company	->		
Location: j-7	k-7	->		
Plant:	West Medway	-> Milbury	**kV:**	345
Utility: nd Power Company	Boston Edison Company	->		
Location: j-7	l-8	->		